

DALMORE CAPITAL

Heating Britain: the case for a two-network transition

THE DALMORE INFRASTRUCTURE SERIES

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Around half of England's homes are rated EPC D or below, and the harder part of that half would cost an estimated £25,000–40,000 each to electrify fully with the fabric work it needs — and the deeper constraint is that heat is a peak problem: on gas-industry modelling published in 2020, full electrification points to a 2050 system peak near 204 GW, against around 116 GW on a hybrid-led pathway. Alistair Ray, Chief Investment Officer of Dalmore Capital argues that the fastest, most affordable route to decarbonising British heat runs through two networks — the electricity grid and a smaller, greener gas network — and maps the investable consequences, from biomethane and storage to the gas networks themselves.

1. KEY POINTS

- Heat decarbonisation is running far below any net-zero pathway, and an order of magnitude below the 2035 rate: 2025's record year — just over 60,000 MCS-certified installations, or around 110,000 hydronic heat pumps on manufacturers' sales figures, a wider measure that counts new build and uncertified work — ran at a seventh to a quarter of the Climate Change Committee's 2030 requirement and a twenty-fifth to a fourteenth of its 2035 rate — and in January 2026 the Government replaced the 2021 target with a lower one rather than close the gap. Each year of shortfall locks in another cohort of fifteen-year gas boilers.
- Around half the housing stock is rated EPC D or below, and the harder-to-treat part of it is expensive to electrify fully: feasible, as the Catapult demonstration showed (at an average installed cost of about £14,800 a property), but at an estimated £25,000–40,000 per home where deep fabric work is needed for comfort and efficiency — and, on a common whole-life basis, at a cost per tonne above the central government appraisal benchmark in the hard-to-treat example examined here, on the Treasury's discount rate or a household's.
- Heat is a peak problem, not an energy problem: gas-industry modelling from 2020 (flagged as such) puts the 2050 GB peak near 204 GW under full electrification against around 116 GW hybrid-led — an 88 GW difference between two modelled scenarios.
- The two-network answer: heat pumps for the efficient half, heat networks for dense urban stock, hybrids on progressively greener gas for the hard remainder — abating most emissions now rather than all emissions never, but only if gas-network exit is zonally planned rather than left to the death spiral.
- What has to be true is stated, not assumed: biomethane must scale (NESO's July 2026 study finds that around 30 TWh a year can be produced by 2050 before material trade-offs arise — of the same order as the residual domestic load, before competing uses), the industry-commissioned parts of the evidence base are flagged and the case is built on the conservative numbers and on arithmetic any reader can check, and six precedent-based policies are required — on which 2026 brought half-steps on two, a reaffirmed exclusion on one and silence on the rest.
- Cost-per-tonne discipline makes the case robust across carbon values — on a common whole-life basis hybrids abate at roughly £235–385 per tonne across the price bases and discount rates examined (£55–180 more where a new boiler is bought with the heat pump) — at or around the government's own carbon value — against roughly £460–1,100 for forced deep retrofit of the same home on the same bases — and, as 2026's gas-price shock showed, across fuel prices too; it maps to an overlooked asset set: biomethane platforms, storage, flexible generation, heat networks and the gas networks themselves.

2. EXECUTIVE SUMMARY

The decarbonisation of British home heating is not going to plan. Heat pump installations reached a record in 2025 but fell in the first half of 2026 — and still run at a seventh to a quarter of the rate the Climate Change Committee's pathway requires by 2030, depending on whether certified installations or manufacturers' sales are counted, and a twenty-fifth to a fourteenth of its 2035 rate; in January 2026 the Government's Warm Homes Plan replaced the 2021 target with a lower one rather than close the gap.[2,3,4] Each year of shortfall locks in another cohort of 15-year gas boilers.[30] This paper argues that the problem is not a lack of commitment but a strategy mismatched to the housing stock, the electricity system and household economics — and that a better strategy is available, one with significant implications for infrastructure investors.

The argument in brief. Around half of England's homes are rated EPC D or below, and the harder part of that half — solid-wall terraces, converted flats, rural properties beyond the reach of heat networks — is expensive to electrify fully, with estimated per-home costs of £25,000–40,000 where deep retrofit is needed.[6] Meanwhile the deeper constraint is systemic: heating is a peak problem. On the gas-industry scenario modelling cited in Section 4 (Cadent, 2020), full electrification of heat would push GB peak electricity demand from ~59 GW in 2020 towards ~204 GW by 2050, whereas a pathway in which harder homes use hybrid heat-pump systems (with hydrogen boilers in that model) peaks at ~116 GW[10] — a difference of 88 GW under that model's assumptions, in peak capacity that need never be built, financed or paid for by consumers.

> *"Crucially, this is a strategy that abates most emissions now rather than all emissions never: hybrids cut a hard-to-treat home's gas use by 60–80% immediately, at a price households will actually pay."*

— Alistair Ray, Chief Investment Officer, Dalmore Capital

The two-network solution. The lower-cost configuration this paper argues for is straightforward: electrify the homes that suit heat pumps (roughly half the stock, plus effectively all new build); connect dense urban areas to heat networks; and serve the difficult remainder with hybrid systems — a heat pump carrying 70–80% of annual demand, a boiler covering the coldest periods — running on progressively greener gas. A gas network serving half its current customers still costs only around £265 per household per year, against £1,600–2,600 a year for the capital cost alone of forcing full electrification on a hard-to-treat home.[26] Crucially, this is a strategy that abates most emissions now rather than all emissions never: hybrids cut a hard-to-treat home's gas use by 60–80% immediately, at a price households will actually pay. Nor is the approach untested: the Netherlands supports hybrids through its ISDE subsidy, and on 7 October 2026 its cabinet announced that from 2029 a smart hybrid heat pump is to become the standard at boiler replacement for homes not on a heat network, with the rules still to be set — a choice framed around lower gas use and grid congestion — and in July 2026 Germany repealed its 2023 requirement that new heating be 65% renewable in favour of fuel standards, carbon pricing and a planned green-gas quota.[25]

2026 has made the case for us. The closure of the Strait of Hormuz at the start of March pushed British wholesale gas prices to more than double their level of a year earlier by late October; the October price cap rose on gas, with electricity held flat only by the VAT cut; and Europe entered the winter with storage at record lows for the time of year while Britain's largest gas store, in its operator's words, stood practically empty, its owner asking for a support framework. A hybrid cuts a hard-to-treat home's gas purchases by 60–80% at a fraction of the capital cost of full electrification, and does so at the next boiler failure rather than at the end of a decade-long retrofit programme. In a year like this one, that is an energy-security policy as much as a carbon policy.[7]

What has to be true. We are careful about what this argument requires. It requires biomethane to scale — the central uncertainty, on which NESO's July 2026 assessment finds that around 30 TWh, about five times today's output, can be reached before material trade-offs arise, with its 64 TWh pathway feasible but warranting a cross-sector assessment, against the industry's 120 TWh.[12,13] Within the low-trade-off case the residual domestic load alone would take most or all of that supply, so where the gas is best used — heat, industry, power or transport — is a question the strategy has to answer rather than assume. It requires exit from the gas network to be spatially planned rather than left to household-by-household attrition, or network economics deteriorate badly. And it requires modest, well-precedented policy: a green gas contract-for-difference to succeed the support scheme closing in 2028, recognition of biomethane in the UK ETS, hybrid eligibility for heat subsidies, and structural rebalancing of the policy levies that still make electricity 3.3 times the price of gas per kWh even after the temporary relief of 2026.[7,8]

The organising principle. Beneath the detail sits a discipline Britain will be forced to adopt sooner or later: minimising the cost of every tonne of carbon saved. The first half of UK decarbonisation was comparatively cheap; the final fifth becomes exponentially more expensive, and at some point another £1 billion spent on gold-plated abatement delivers less than £1 billion spent on other priorities that sit alongside net zero: healthcare, education, flood resilience, nature recovery, air quality and fuel poverty — or adaptation itself. Section 9 addresses this directly: the two-network pathway is what taking marginal abatement cost seriously looks like in heat — buying the cheap tonnes now and holding the expensive tail open until it deflates. That discipline is robust to the value a future government places on carbon: at the government's own carbon value and discount rate the hybrid's tonnes in the hard stock pass and forced deep retrofit's do not; at the far lower traded price nothing in the hard stock passes, and the only rational sequencing is cheapest first — which is the two-network path.

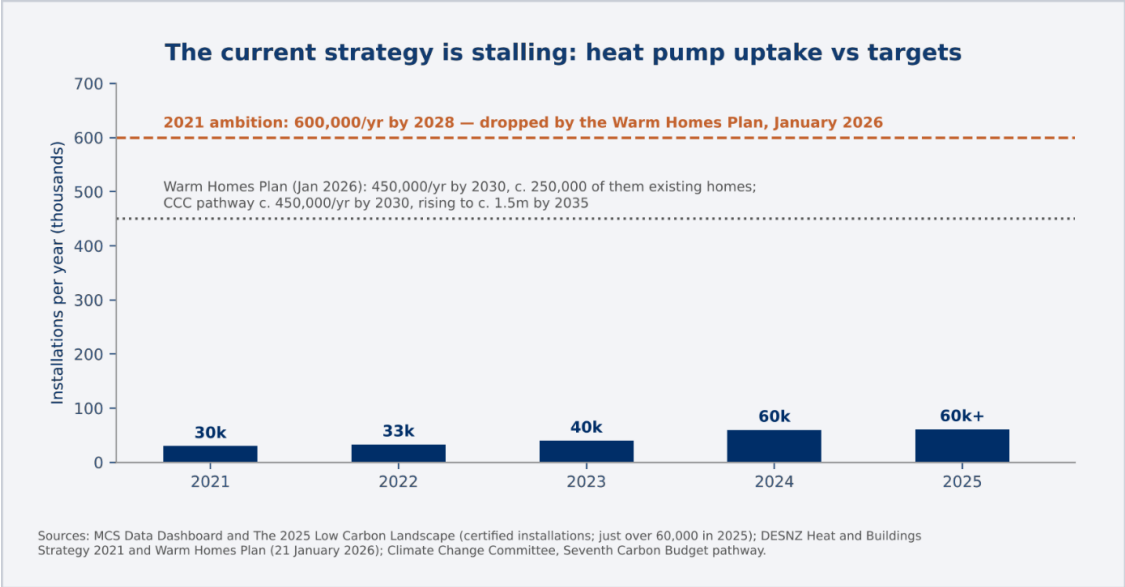
Why this matters to investors. If the transition proceeds this way — and the direction of travel in policy and market behaviour increasingly suggests it will — the investable opportunity set extends well beyond renewable generation: biomethane production platforms, gas and long-duration energy storage, flexible generation, heat networks and the networks themselves. For institutional investors — pension funds, insurers and sovereign wealth — whose net-zero commitments are measured by portfolio footprint and alignment, and increasingly judged on the real-economy abatement behind them, the arithmetic is that this pathway plausibly abates more cumulative carbon this decade than the purist alternative, at materially lower cost. The final section maps the thesis to asset classes.

3. THE TRANSITION'S HARDEST MILE

Direct emissions from buildings account for around 17% of the UK total, mostly from burning natural gas for heating, about 70% of it in homes.[1] No credible route to net zero avoids decarbonising heat. The strategy of the past decade has been, in effect, to electrify everything: heat pumps for existing homes, an ambition — set in 2021 — for market capacity of 600,000 installations a year by 2028,[3] and a pathway from the Climate Change Committee rising to around 450,000 a year by 2030 and 1.5 million a year by 2035.[4] In January 2026 the Warm Homes Plan replaced the 2021 ambition for 2028 with an aim of more than 450,000 a year by 2030, of which only around 250,000 are expected to be existing homes (the technical annex puts c. 200,000 in new build), and set no date for ending new gas boiler installations (the 2021 strategy had pencilled in 2035): the gap between ambition and delivery has been narrowed from the ambition side.[3]

The gap between that ambition and observed behaviour is now too large to attribute to teething problems. MCS-certified installations reached just over 60,000 in 2025 — a record year; manufacturers' factory-gate sales, a wider measure that counts new build and uncertified work, put hydronic heat pumps at about 110,000 (125,037 including other types, up 27% on 2024) — and on either measure an order of magnitude short of the 2035 rate.[2] The demand indicators are improving — Boiler Upgrade Scheme applications hit a record in July 2026 (much of the jump from the new off-gas-grid route) and vouchers paid in August were about 40% above August 2025 — but completed installations fell in the first half of 2026 (MCS-certified down 17%, DESNZ retrofit installations down 22%). Even a full year a third faster than 2025, which would need a second half around 80% up, would leave it at around a third of the Government's reduced target for existing homes, and a twentieth of what the CCC's pathway requires within a

decade.[2] The shortfall is not primarily a technology failure: heat pumps work, and work well, in suitable homes. It is an adoption failure with structural causes — cost, disruption, and the distress-purchase dynamics of a heating market in which a failed boiler is typically replaced within days.[30]



The stakes of the shortfall are cumulative. Carbon dioxide accumulates; a tonne abated in 2028 is worth more than a tonne abated in 2045. A boiler installed in 2036 will often still be running in 2050. Judged by cumulative emissions — the measure the atmosphere actually keeps — a pathway with high uptake beats a purer pathway with low uptake, even if the latter looks better on paper at mid-century. This observation does most of the work in what follows: the search is not for the perfect end state but for the strategy that abates the most carbon fastest, at costs households and the state can bear.

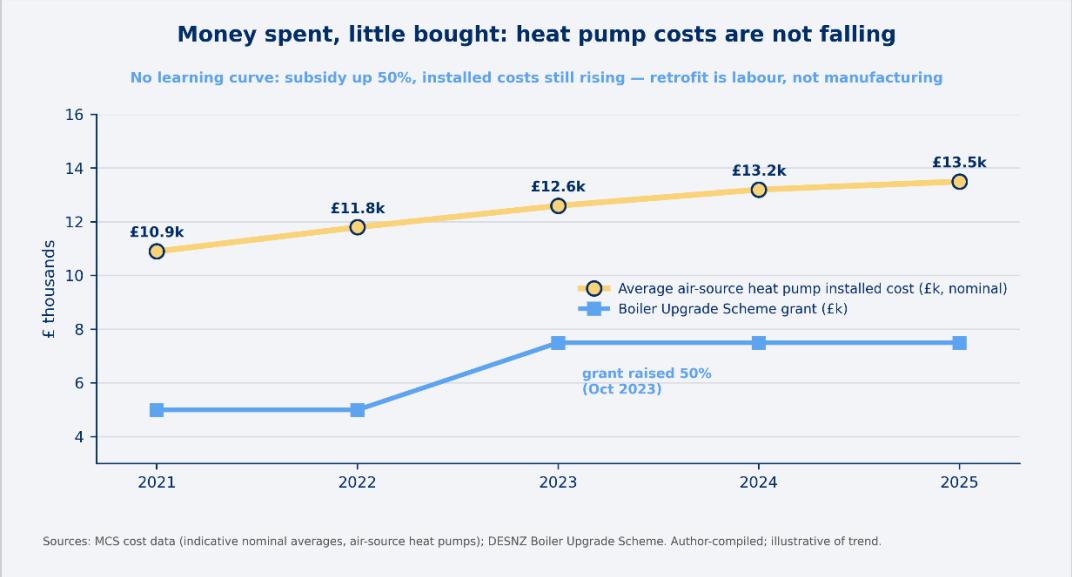
4. WHY TODAY'S STRATEGY IS FAILING

The failure has a mechanism, and it fits on one page.

Ambition is set centrally; the consumer economics — an electricity price 3.3 times the gas price even after 2026's temporary relief, and £25,000–40,000 of works for the hard half of the stock — are left unreformed; adoption disappoints; and the heating market does what it always does when a boiler dies on a Friday night: replaces it like-for-like within days — in a market selling around 1.5 million boilers a year.[35] Each replacement locks in fifteen years of gas use. The response to date has been to restate the ambition — and, in 2026, to reduce it — rather than repair the economics beneath it. The framing compounds the failure. Households are offered a binary choice — install a full heat pump now, or keep the gas boiler and wait — so the middle ground that holds much of the hard stock's near-term abatement barely features in policy design at all.

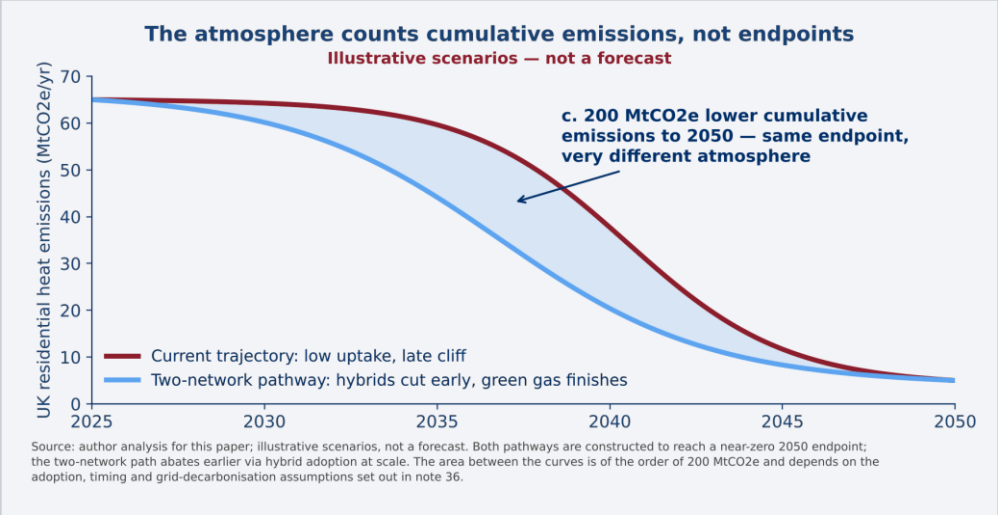


Nor is time solving the problem. The learning-curve logic that rescued offshore wind — deploy, scale, watch costs fall — is not operating in domestic retrofit, because retrofit is labour in kitchens rather than manufacturing in factories. Average installed heat pump costs (MCS) have risen in cash terms through years of record subsidy, while the median Boiler Upgrade Scheme installation cost has fallen by about 11% in real terms since 2022 — partly through a shift to smaller systems, and flat in the latest year; the grant was lifted 50% in 2023 and the gap did not close.[35]



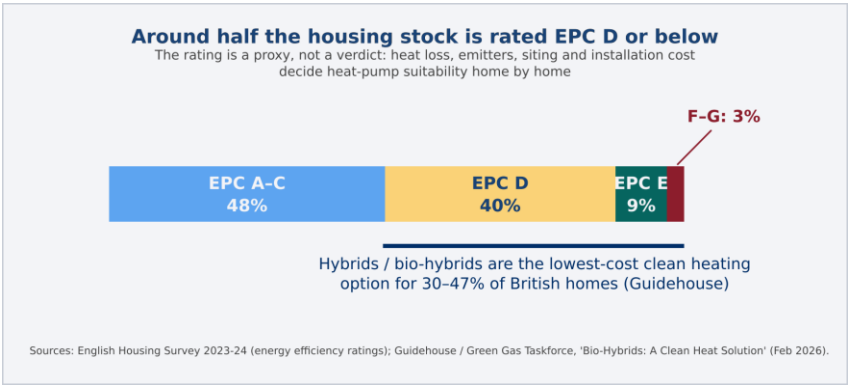
The consequence is measured not in any single year's shortfall but in the area under the curve. Both the current strategy and the two-network pathway set out in this paper can reach a near-zero endpoint in 2050; what differs is the route. A strategy that waits for perfect solutions holds emissions high through the 2030s and then requires an implausible cliff; a strategy that abates 60–80% of each hard home's emissions at the next boiler replacement starts

cutting now. On illustrative assumptions the difference is of the order of 200 MtCO2e of cumulative emissions — several years' worth of the entire sector's output — from strategies that look identical on an endpoint chart.[36]



5. WHY HALF THE HOUSING STOCK RESISTS

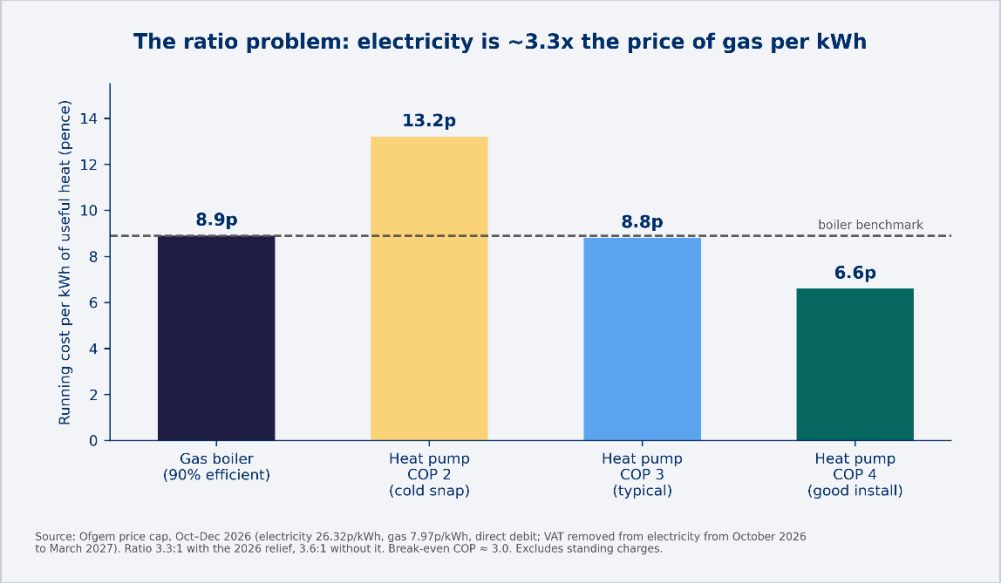
Britain has some of the oldest housing in Europe. Around 40% of homes in England are rated EPC D and a further 9% E or below;[5] roughly a fifth of the stock in England was built before 1919, and most of it has solid walls. Around four in five of the buildings that will be in use in 2050 have already been built. For the efficient half of the stock — and effectively all new construction, from which the Future Homes Standard all but removes the gas boiler from March 2027 (with a 12-month transition) — heat pumps are the right answer, and nothing in this paper argues otherwise.[3]



The difficult half is difficult for compounding reasons. Solid-wall properties need expensive insulation — external cladding that faces planning obstacles, or internal insulation that consumes floor space — before a standard heat pump can heat them economically. Converted flats with combination boilers have no space for a hot water cylinder, nowhere compliant to site an outdoor unit, and freehold/leasehold structures in which no individual household can decide anything. High-temperature heat pumps address some cases at a premium; heat networks will ultimately serve much of the dense urban stock.[23] The Catapult's Electrification of Heat demonstration installed 742 heat pumps across the full range of targeted property types, pre-1945 stock included, and found no archetype unsuitable — so the question for the hard half is not feasibility but cost and comfort: a heat pump dropped into an uninsulated solid-wall home runs at a poor coefficient of performance and a heavy peak draw, and the fabric work that cures both is what

takes the bill to £25,000–40,000 per home[6] — sums that are unaffordable to most households and, multiplied across millions of homes, to the country.

Household economics compound the capital problem. Under the price cap for the last quarter of 2026, electricity costs 3.3 times as much as gas per kWh — down from 3.6 a quarter earlier only because VAT was lifted from electricity for six months and gas rose with the Gulf crisis — partly because historic policy levies sit on electricity bills; so a heat pump must sustain a coefficient of performance above roughly 3.0 merely to match a boiler's running costs, and above roughly 3.1 once the VAT relief lapses (3.2 on the July–September cap).[7] Well-installed systems in well-insulated homes clear that bar; average installations in poor housing stock often do not. Both the CCC and NESO have recommended rebalancing levies,[8] and doing so is among the cheapest single accelerants available to the transition. The Government has taken two steps in that direction — three-quarters of the Renewables Obligation moved from bills to taxation for three years from April 2026, and VAT removed from electricity from October 2026 to March 2027 — but both are time-limited, and neither touches the structure of the levies. Until that happens, the consumer case for electrified heat is weakest precisely where the housing is hardest.



Independent granularity on this segment is limited, and the most detailed stock modelling available was published by a gas-industry taskforce — a fact we flag rather than hide. Guidehouse's analysis for the Green Gas Taskforce finds bio-hybrids (hybrids on a green gas tariff) to be the lowest-cost clean heating option for 30–47% of British residential buildings on its headline figure (30–45% in its modelling results): all EPC E and F stock in every building type, and band D in selected building types, mainly detached houses.[9] Our own triangulation from the stock data lands in the same range — roughly a third of homes, after netting off the dense urban share better served by heat networks. The precise figure matters less than its robustness: under every assumption set we have examined, the segment for which full electrification is the wrong answer on cost is measured in millions of homes.

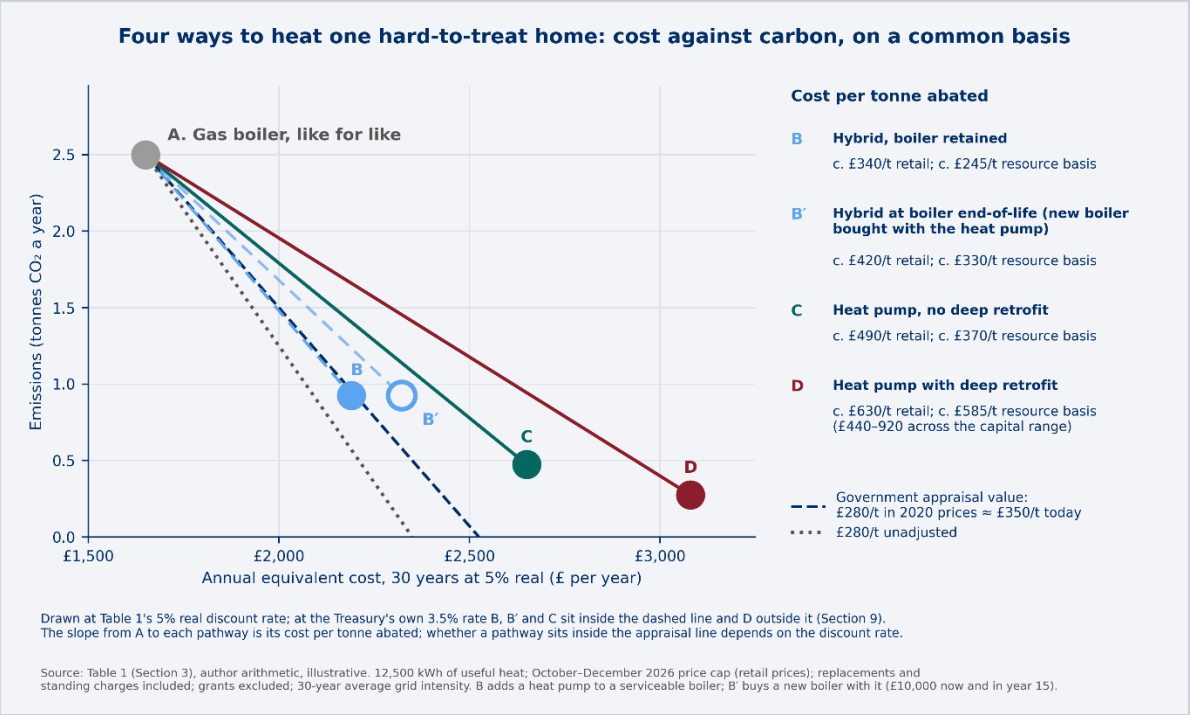
> *"Hybrids are not being rejected by households; they are barely being offered to them."*
>
> — Alistair Ray, Chief Investment Officer, Dalmore Capital

Which raises an obvious question: if hybrids are the lowest-cost answer for millions of homes, why is almost nobody installing them? Four barriers explain the gap, and none of them is technical. The first is upfront cost. Industry guidance puts the cost of adding a heat pump alongside an existing boiler at £5,000–8,000 — a fraction of the

£25,000–40,000 that full electrification with fabric work requires, but roughly 1.4 to 2.3 times the price of the like-for-like boiler swap that most households are actually choosing, usually in a hurry.[6] The case rests on that add-on route: an integrated hybrid unit at £11,000 costs about as much per tonne as a heat pump without fabric work, and at the £12,000 or more some suppliers quote it costs more. Table 1 puts the alternatives on a common basis — the same home, thirty years, every replacement, every unit of energy and every standing charge — and the hybrid remains the cheapest route to most of the home's abatement on every view, whether the heat pump is added to a serviceable boiler, as the Dutch do, or bought with a new boiler when the old one fails, which adds about £80 a tonne at the paper's discount rate; the full heat pump without fabric work matches it for the household only because the taxpayer pays £7,500 of the bill, and even then costs the country about half as much again per tonne and depends on a heat pump sized for the coldest days in an uninsulated home — the peak-draw problem Section 4 sets out. The second is subsidy design, which inverts the incentive: in England and Wales a full heat pump attracts a £7,500 Boiler Upgrade Scheme grant (£9,000 for off-gas-grid homes replacing oil or LPG, until 31 March 2027); a hybrid attracts nothing — and the April 2026 regulations, which added a £2,500 grant for air-to-air units, reaffirmed the exclusion: the heat pump must meet the home's full heating demand on its own, and any supplementary appliance must be fossil-free.[28] The option with the lowest whole-system cost is therefore the most expensive one on the householder's quote. It also means a Treasury looking for savings in the heat budget has a better option than shrinking the scheme. On Table 1's numbers, a £2,500 hybrid grant buys a tonne a year of abatement in a hard-to-treat home for about £1,600 of Exchequer money; the £7,500 full-heat-pump grant buys it in the same home for about £3,600. Re-pointing part of the budget at the cheaper tonnes would cut the bill and raise the abatement at the same time. The third is running costs: the 3.3:1 electricity-to-gas price ratio described above blunts the savings case for the heat-pump half of the system. And the fourth follows from the first three: installers have little reason to recommend — or even mention — a product that neither subsidy nor regulation rewards. Hybrids are not being rejected by households; they are barely being offered to them. That is a failure of policy design, not of economics — which is why the remedies in Section 10 are cheap.

Table 1. Thirty years of heating one hard-to-treat home: four pathways on a common basis (illustrative)[37]

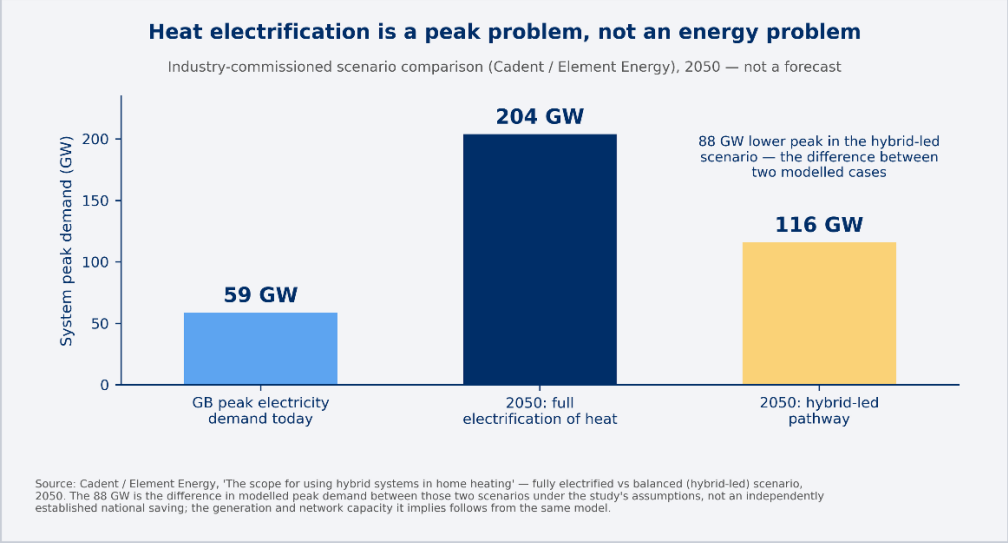
	A. Boiler, like for like	B. Hybrid: heat pump added, boiler retained (ten years of life left)	C. Heat pump, no deep retrofit	D. Heat pump with deep retrofit
Capital cost now	£3,500	£6,500	£15,000	£30,000
Replacements within 30 years	Boiler at year 15 (£3,500)	Heat pump at year 15 (£6,500); boiler at years 10 and 25 (£3,500 each)	Heat pump at year 15 (£10,000)	Heat pump at year 15 (£10,000)
Annual running cost: energy, standing charges, maintenance	£1,315	£1,360	£1,365	£820
Annual equivalent cost, 30 years at 5% real	£1,650	£2,190	£2,650	£3,080
Emissions, tonnes CO2 a year (30-year average grid)	2.5	0.95	0.5	0.3
Abatement against A	—	1.6 t (63%)	2.1 t (81%)	2.3 t (89%)
Cost per tonne abated	—	c. £340 at retail prices; c. £245 on a resource-cost basis; c. £250 with kit at £5,000; c. £420 / £330 at boiler end-of-life (new boiler bought with the heat pump)	c. £490 at retail prices; c. £370 on a resource-cost basis	c. £630 (£490–920 across £25,000–40,000); c. £585 on a resource-cost basis



6. HEAT IS A PEAK PROBLEM, NOT AN ENERGY PROBLEM

The deeper constraint is not inside the home but in the system around it. On a peak winter day the gas network delivers roughly four times the electricity network's energy.[31]

Electrifying heat in full means rebuilding that peak capability in wires, generation and storage. Cadent's 2020 modelling puts 2050 GB system peak demand at around 204 GW in a fully electrified scenario, against around 116 GW in a "balanced" scenario where hybrids with hydrogen boilers dominate[10] — and while the figures are the gas industry's own, and the hybrid case assumes hydrogen rather than biomethane, the direction and rough magnitude follow from arithmetic no one disputes: heat is the largest swing component of winter demand, and peak capacity is the most expensive kind.

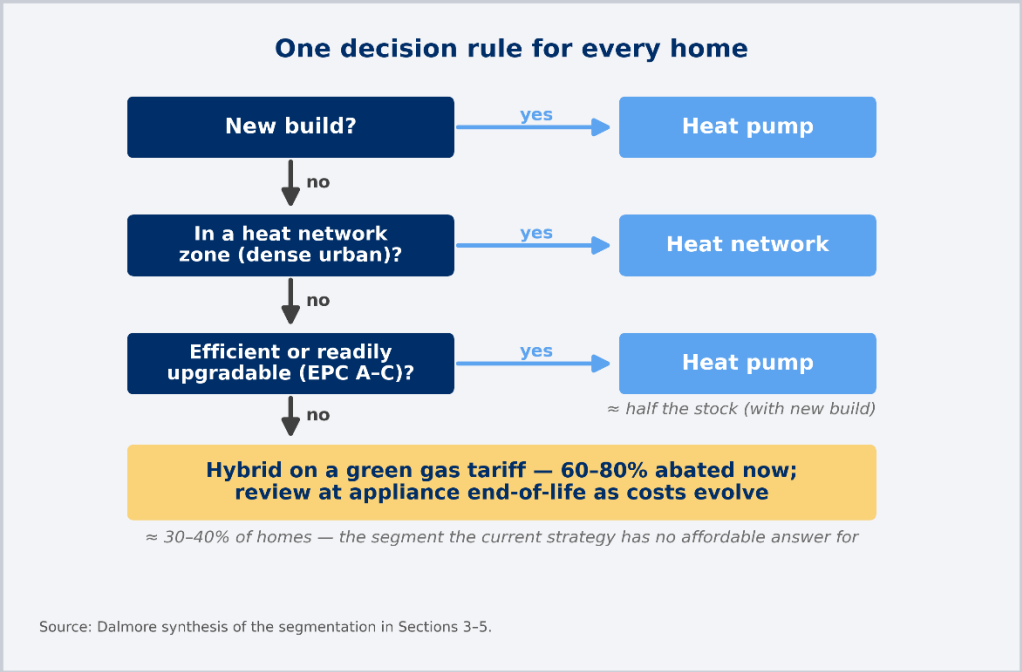


Renewables economics sharpen the point. The value of intermittent generation declines with penetration — each additional wind farm produces disproportionately at moments when power is already abundant[11] — while the costs of accommodating it (backup capacity, constraint payments, storage, transmission) rise. Great Britain's low-carbon share is now high enough that these integration costs are material, and the cost curve is convex at the top: moving towards 100% renewable coverage means building capacity for progressively rarer events, culminating in the prolonged windless cold spell that batteries cannot economically cover. NESO's own scenarios therefore retain at least 50 GW of dispatchable thermal capacity in 2050 — gas with carbon capture, and hydrogen-fired plant — running rarely, existing as insurance.[31]

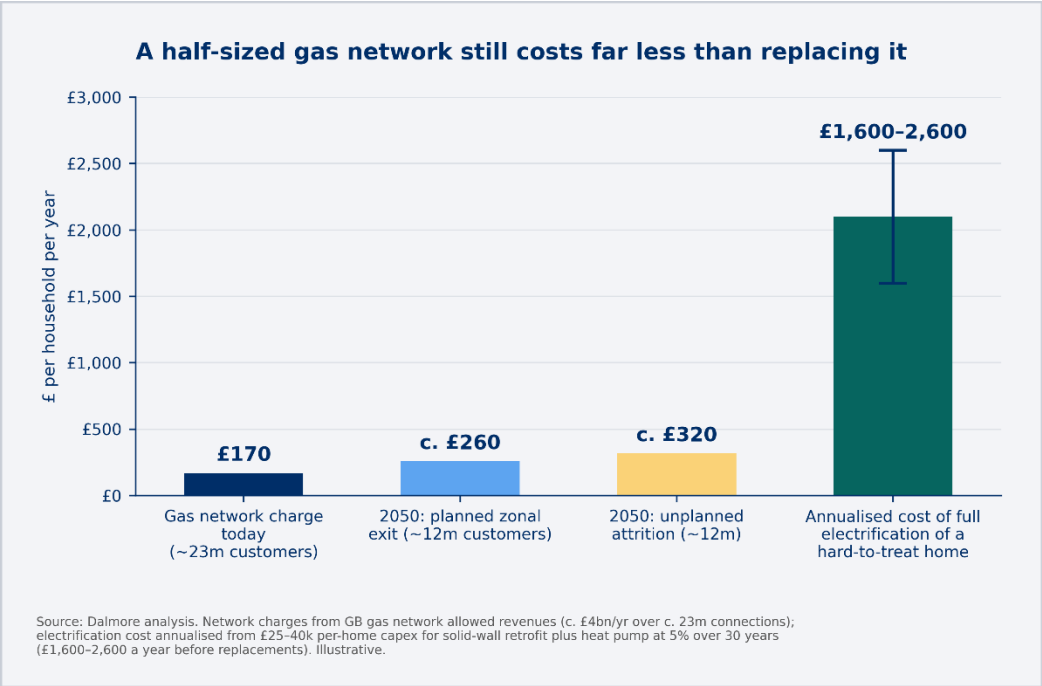
Once that residual dispatchable capacity is accepted, a question follows that is asked less often than it should be: if gas is to be burned in rare peak conditions anyway, where should it be burned? The thermodynamics at system peak are instructive. A condensing boiler delivers about 0.9 units of heat per unit of gas at the point of use. The electrified chain — power station at ~55% efficiency, c. 7–8% network losses, then a heat pump at a cold-snap COP of ~2 — delivers about 1.0.[27] A marginal gain, purchased at the price of the entire peak generation and network capacity chain standing behind it. For the specific hours that drive system investment, moving molecules and burning them at the point of use is the cheaper engineering answer. For the other 90% of the year, the heat pump — at a COP of 3 to 4 on increasingly cheap renewable electricity — wins decisively. The system that follows from taking both facts seriously is the hybrid: electric heat most of the year, gas at the peak, and an electricity system sized for a much flatter demand curve.

7. THE TWO-NETWORK SOLUTION

Assembled, the strategy looks like this. Heat pumps for the efficient half of the stock and all new build. Heat networks for dense urban areas, under the zoning powers now in statute.[23] Hybrid systems for the difficult remainder — the heat pump carrying 70–80% of annual demand, the boiler covering cold periods, cutting gas use by 60–80% per home immediately. And a gas network that shrinks by design: our estimate is that 30–40% of homes retain a connection through mid-century, mostly as hybrids, which — combined with industrial demand, flexible generation and new loads — is of a similar order to the roughly 40% of 2024's gas demand that NESO's Holistic Transition pathway retains in 2050 — though that pathway has almost no residential gas, so the comparison is of totals only.[12]

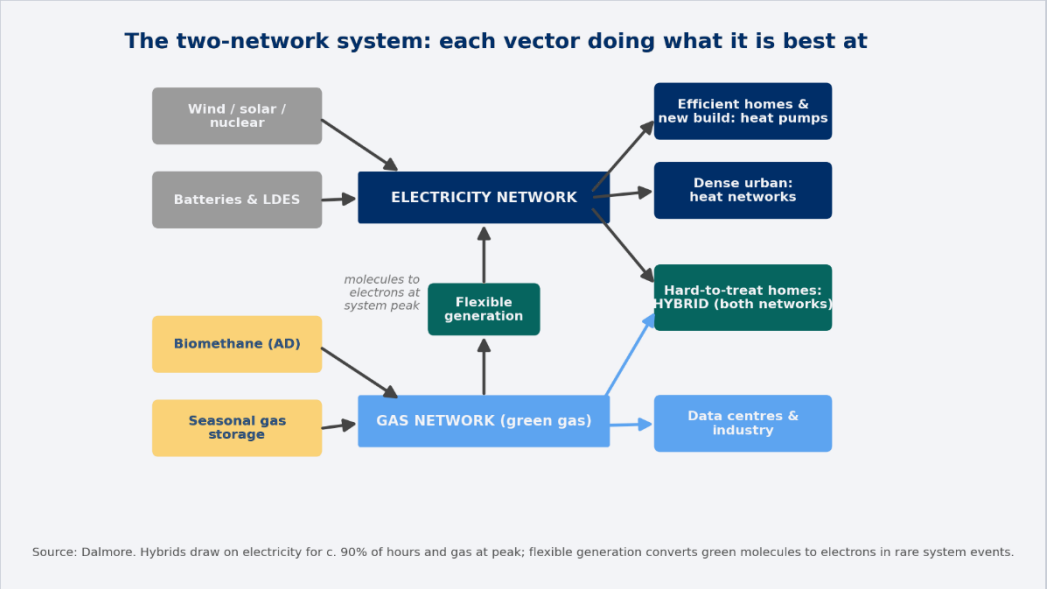


The first objection is cost: is it not wasteful to run two networks? The arithmetic says otherwise. GB gas network charges today are roughly £180 per household per year (Ofgem's figure for a typical dual-fuel home: £165 for distribution plus £13 for transmission). Halve the customer base with planned, zonal exit and the figure rises to around £265; even under badly managed attrition it reaches only around £330. At the 30–40% retention this paper assumes in Section 6, and with costs still at 70–80% of today's, the planned-exit figure is £310–475 a year.[26] Against the £1,600–2,600 a year that the capital cost alone of fully electrifying a hard-to-treat home comes to,[6] retaining the pipe is not a close call. Ofgem's acceleration of gas distribution depreciation strengthens the end state further: new investment is being paid back by 2050 while the customer base is still broad, so the half-sized network of 2050 carries less new-build asset value for a smaller base to repay.[24]



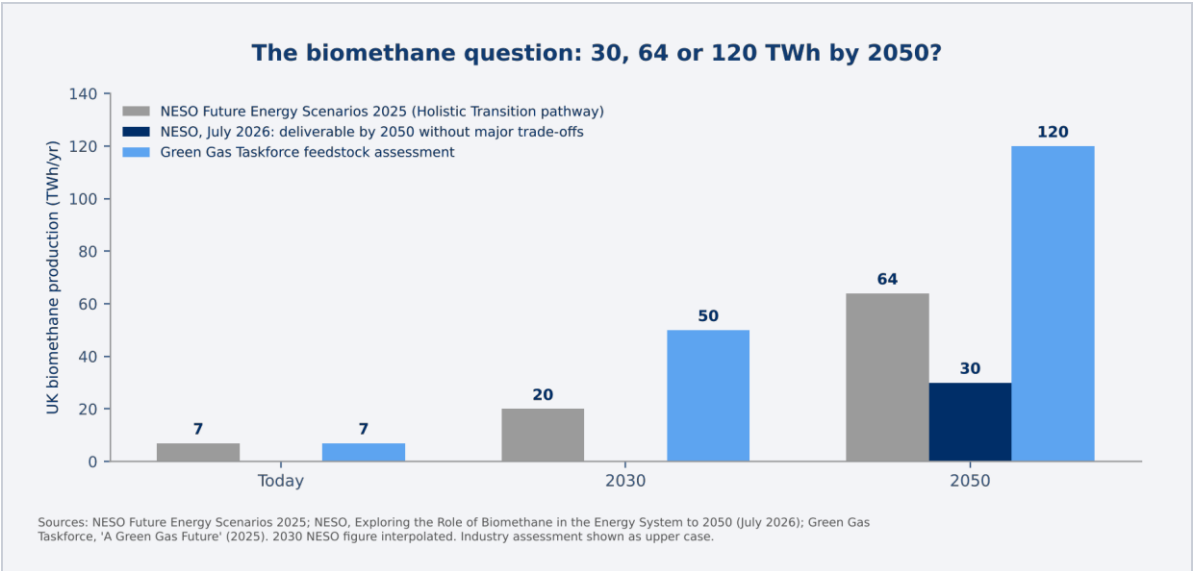
The serious objection is not the average cost but the dynamics: gas network costs are driven by geography, not throughput, and the easy and hard homes are interleaved on the same streets. If exit happens household by household, the full network footprint must be maintained for a thinning, scattered base — unit costs climb, and because remaining gas users skew towards older, poorer housing, the distributional consequences are regressive. This is the death spiral, and it is the strongest argument against the two-network model done carelessly. The remedy is known: street-by-street and zone-by-zone planning of the kind Denmark practises and the Netherlands plans to introduce, in which whole network sections are either retained or decommissioned. The Netherlands is explicit about the logic, favouring hybrid systems — a 2021 network-operator-led coalition proposed up to 2 million by 2030, and on 7 October 2026 the cabinet announced that from 2029 smart hybrids are to become the standard at boiler replacement — for their contribution to managing peak demand and grid congestion.[25] Germany, which legislated in 2023 a requirement that new heating systems run on 65% renewable energy, repealed it in July 2026 in favour of minimum green-fuel shares for new gas and oil systems from 2029, carbon pricing and a planned quota for green gas and heating oil — a two-network pivot by the country that tried hardest to legislate its way to renewable heating.[25] England's heat network zoning — a national Zoning Authority, local coordination bodies and the first regulations due in 2026 — is a first institutional step; what is missing is the authority to draw the whole map.[23] We return to this in the policy section, because it is the pivot on which the strategy's economics turn.

The system that results assigns each vector to what it does best: electrons for efficient year-round heat, molecules for peak resilience and hard-to-serve loads, and flexible generation converting one into the other in rare system events.



8. GREENING THE MOLECULE

A retained gas network is only net-zero-compliant if what flows through it decarbonises. The leading candidate is biomethane — chemically interchangeable with natural gas, injectable today without appliance changes, and produced from wastes and agricultural feedstocks with strong circular-economy characteristics: digestate returns nutrients to farmland, and captured CO2 is itself a saleable product. The UK produces about 6–7 TWh a year. The question that matters is how far that scales.



The answer is contested, but less so than a year ago. In July 2026 NESO, the system operator, published its own assessment: around 30 TWh a year — about five times today's output — can be produced by 2050 before material trade-offs arise, and the 64 TWh in its Future Energy Scenarios is feasible but warrants a cross-sector assessment, with some feedstock potential, notably grassland, depending on the 38% fall in livestock numbers in the CCC's balanced

pathway; the Green Gas Taskforce's feedstock assessment (also by Alder BioInsights), by contrast, finds 120 TWh of sustainable UK feedstock by 2050 and argues that cropping for anaerobic digestion should not be seen as competing with food production.[13] The industry number, if right, would make the residual network's supply question comfortable — and commissioned analysis puts the energy-system savings from scaling biomethane at £150–220bn by 2050 (central case c. £174bn), with production costs falling around 25% as barriers are removed,[14] alongside some 57,000 jobs by 2050 on the Taskforce's c. 111 TWh central case, skewed to rural and semi-rural areas (about 15,000 in rural communities).[15] We cite these figures with their provenance attached: they come from the sector that benefits from them, and we said these numbers needed independent testing — NESO has now marked where the trade-offs begin — though its feedstock evidence comes from the same consultancy as the Taskforce's and is close to it (up to 108 TWh for Great Britain against 120 TWh for the UK); its 30 TWh and 64 TWh are points at which trade-offs and dependencies emerge, not a rival feedstock estimate. On this paper's own arithmetic, the residual domestic load is of the same order as NESO's 30 TWh figure: 30–40% of homes retaining a connection, most of them hybrids using a fifth to two-fifths of their former gas, implies domestic demand of the order of 25–35 TWh on central assumptions — of a similar order to NESO's 30 TWh low-trade-off supply, which is a national figure rather than one reserved for homes, so that industry, power and transport would be competing for the same gas rather than for a remainder.[13] What is not contested is the direction: feedstock is not the binding constraint at current volumes nor, on NESO's reading, at several multiples of them; the UK runs well behind comparable European markets; and France — with a regulator-supervised 'right to inject', shared reinforcement costs and more than 800 plants connected — demonstrates that policy design, not feedstock, sets the pace.[16,32]

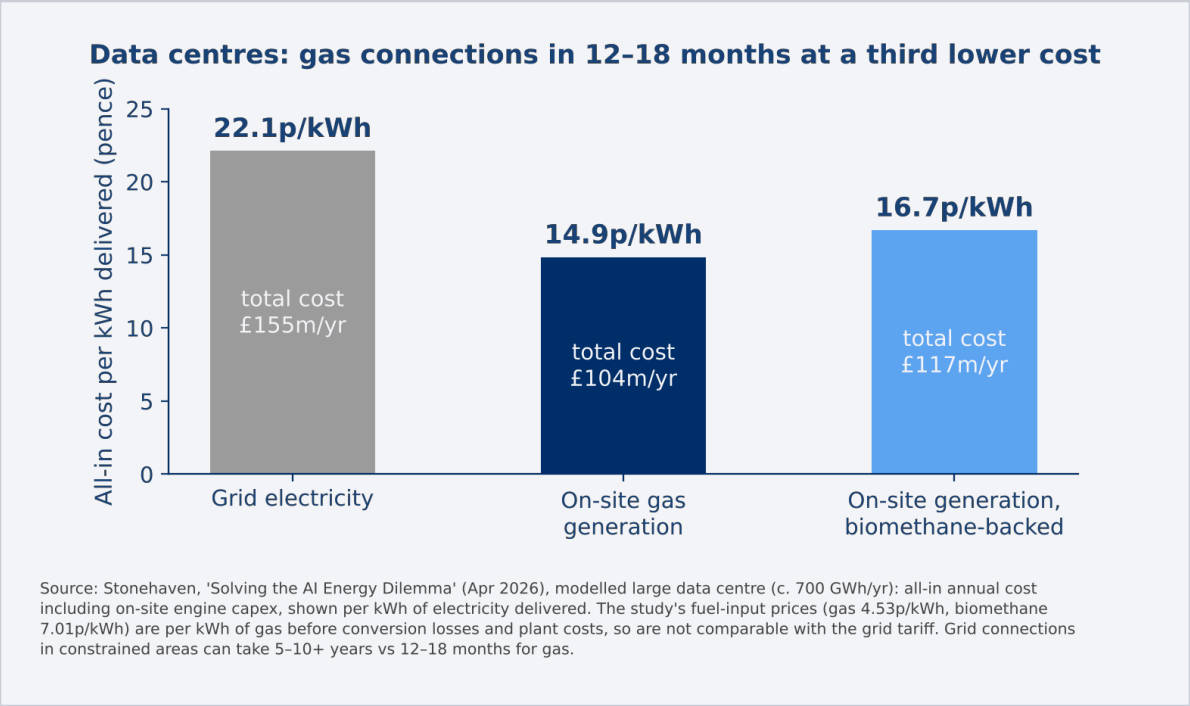
The instrument is familiar. The Green Gas Support Scheme closes to new applicants in March 2028; the Government's extension of the commissioning deadline to 2030, announced in December 2025, took ten months to reach the statute book and comes into force in October 2026; the successor framework it said it expected to consult on by the end of the 2025/26 financial year had still not appeared by October.[17] The natural replacement is a contract-for-difference, auctioned as in power markets. The mechanism's value is precisely the one it demonstrated for offshore wind — and it is worth being accurate about what that was. Part of offshore wind's cost decline came not from hardware but from cheaper, de-risked capital: strip merchant price risk from a capital-intensive asset and its cost of capital, and hence its delivered cost, falls sharply.[18] Anaerobic digestion plants have the same financial anatomy. A biomethane CfD — with feedstock-cost indexation, funded from gas rather than electricity bills (which simultaneously helps the levy-rebalancing case) — is the single most direct way to test whether the industry's cost claims are real, because auctions reveal costs that reports can only assert. Alongside it sits recognition of grid-injected biomethane in the UK ETS, which the EU ETS already provides, subject to sustainability and traceability conditions.[29] One dependence deserves flagging honestly: unlike the core two-network case, which strengthens as carbon values fall (see Section 9), the value of the green molecule leans on carbon being priced meaningfully — through ETS recognition, a CfD strike, or both — and investors should underwrite it as policy-contingent option value rather than as the base case.

A word on hydrogen, because candour here is what separates analysis from advocacy. Blending up to 20% hydrogen by volume performed safely in trials on the distribution network — though the regulator's assessment is the gating item — but delivers only about 7% by energy, since hydrogen is much less energy-dense.[19] Blending's real function is as an offtaker of last resort supporting a nascent hydrogen production sector, which is broadly how government has framed it.[20] Hydrogen for home heating has, for now, lost the argument: the village trials were cancelled, the CCC sees no role for it in heating buildings, the efficiency chain is unfavourable, and in 2026 the Government itself called it "not yet a proven technology" with a role that “would come later and likely be limited", deferring any decision to a future consultation.[21] Hydrogen's network future lies in industrial clusters and flexible power. The residual heating network's molecule is biomethane, and the investment case should be built on that basis, with hydrogen as optionality rather than premise.

9. NEW DEMAND: DATA CENTRES AND FLEXIBLE POWER

The two-network model's economics improve further if the gas system carries new productive load while domestic demand declines. The most significant is data centres. Applicants for the Government's AI Growth Zones must

demonstrate access to at least 500 MW of power capacity by 2030; electricity connections in constrained areas can take a decade, against 12–18 months for gas.[22] Developers have noticed: modelled costs for a large facility show on-site gas generation at roughly a third below grid electricity, and a biomethane-backed configuration below grid cost if biomethane injection is recognised under the UK ETS — on today's treatment it is 12% above.[28] Gas here is not a rival to electrification but a bridge that lets internationally mobile investment land now, while the electricity system expands — and, backed by green gas, a bridge with a credible net-zero destination.



The same logic applies to flexible generation. The convex tail of Section 4 implies enduring value in dispatchable capacity that runs rarely — gas peakers transitioning to green gas, alongside batteries for shorter durations and long-duration storage as it matures. Seasonal gas storage, scarce in the UK since Rough's long shutdown and partial return, carries insurance value the market has historically under-rewarded — and 2026 showed what that looks like in practice: Rough stood practically empty through a gas-price shock, its operator warning in September that it would close by spring 2027 without a support framework, while the Government's interim response on gas security recorded respondents' doubts that the market will fund storage unaided, accepted that "a long-term commercial model in the form of financial or revenue support may be required", and noted cap-and-floor as the model most commonly favoured by operators.[31] A system explicitly designed around a residual gas network for peak heat makes that value legible — and contractable. For network economics, every unit of non-domestic throughput — data centres, industry, power generation — spreads fixed costs and blunts the death-spiral risk.

10. WHAT WOULD NEED TO BE TRUE — CAVEATS AND TESTS

An argument is only as strong as its treatment of the ways it could be wrong. Four deserve to be stated plainly.

The evidence base is heavily industry-commissioned. Much of the granular modelling cited here — Guidehouse, Baringa, Stonehaven and Cadent's own modelling — was paid for, or published, by gas networks or their taskforce. That does not make it wrong; it makes it unverified. No authoritative, independent whole-system comparison of a planned two-network pathway against full electrification on consistent assumptions yet exists; NESO's biomethane assessment has supplied one piece of it. This paper does not wait for the rest: it builds the case on the conservative

numbers, on arithmetic set out in full (Table 1 and the notes) and on system facts no one disputes — and we would expect the case to survive any such comparison, which we would welcome. In the same spirit of disclosure: Dalmore-managed vehicles hold interests in Cadent Gas, whose commissioned research is cited in this paper, Cory Riverside, including its proposed London heat transmission main, a portfolio of EDF onshore wind assets, Scottish run-of-river hydro assets and an offshore transmission (OFTO) asset — positions on both sides of the electrons-and-molecules divide. Readers should weigh our conclusions accordingly; it is precisely because we own assets in both systems that we are interested in the configuration that decarbonises fastest, rather than in either side winning the argument.

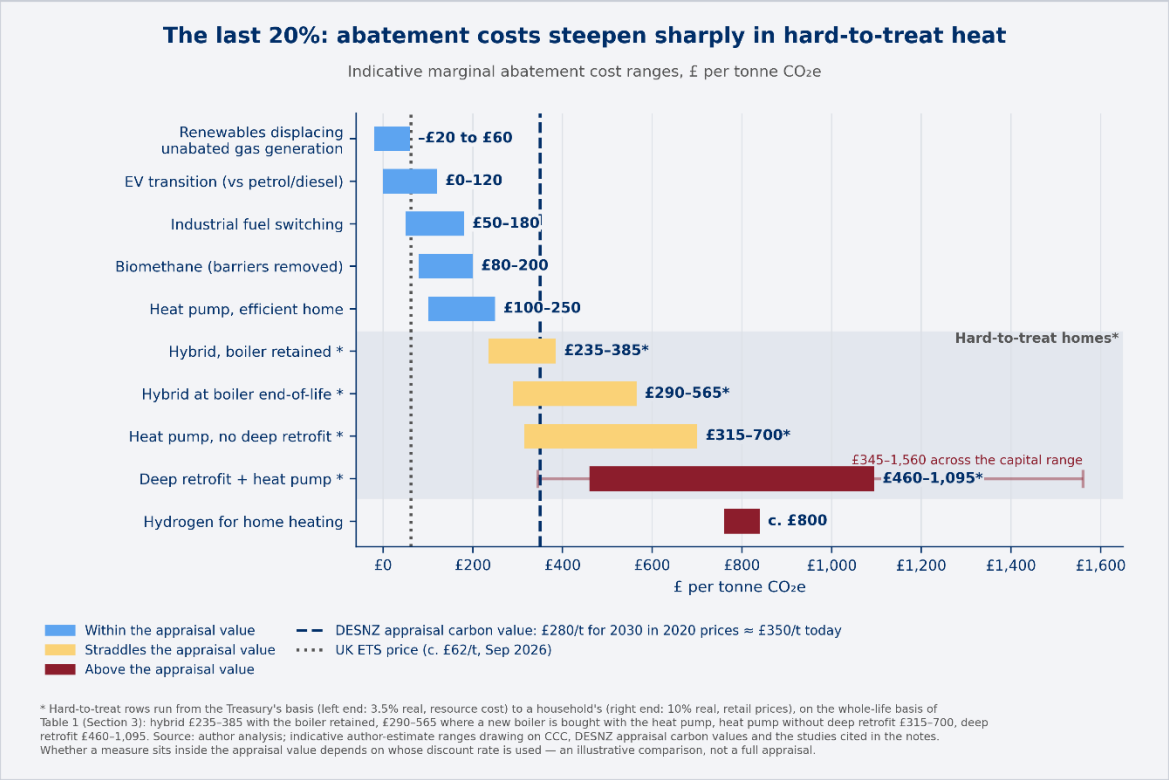
Lock-in risk is real. The charge against hybrids is that the boiler half quietly becomes permanent and the green gas never arrives. The answer is mechanism design rather than reassurance: rising biomethane blending obligations, sunset reviews tied to independent supply audits, and hybrid subsidies conditional on certified green gas tariffs — so that the bridge carries its own enforcement.

The death spiral is avoidable, not avoided. Everything in Section 5 depends on exit from the network being planned. The politics of telling a street it is losing its gas main — or keeping it — are genuinely difficult, and the institutional machinery does not yet exist. Investors should treat the creation (or failure) of zonal heat planning authority as a leading indicator for the whole thesis, with the rebalancing of policy levies and the confirmation of a successor to the Green Gas Support Scheme (GGSS) as the two supporting signals to watch — on both of which 2026 delivered half-steps: temporary bill relief rather than structural rebalancing, and an extension of the existing scheme rather than its successor.

The consensus could be right. If heat pump costs fall faster than expected, levies are rebalanced and retrofit economics improve, the segment for which hybrids are optimal shrinks — perhaps to 20–25% of homes. We note two things. First, the two-network strategy is robust to that outcome: hybrids convert to full heat pumps at end of life, and the network shrinks further by plan; the option has been kept open at low cost. Second, the reverse is not true — a forced-electrification strategy that stalls has no comparable fallback. Asymmetry of regret favours the flexible path.

11. THE ECONOMICS OF THE LAST 20%

Standing back from heat specifically, the whole argument of this paper is an instance of a discipline that surprisingly few net zero documents apply explicitly: minimising the cost of every tonne of carbon saved. Britain's decarbonisation so far has followed the marginal abatement cost curve downhill. The first half — roughly, the halving of territorial emissions since 1990, achieved while the economy grew by close to nine-tenths — was comparatively cheap: exiting coal, building renewables whose costs fell as they scaled, and industrial change.[33] The next tranche — transport, industry, the efficient half of housing — is harder but still clears any sensible cost-benefit test. It is the final portion where the curve turns near-vertical: deep retrofit of the hardest homes, hydrogen for heat, capacity for the rarest system events. And the difference is not merely one of degree. Coal could be replaced by decisions taken in a handful of boardrooms and one department of state; decarbonising the last fifth of emissions means entering millions of people's homes. That changes both the economics and the politics — and it is why strategies that ignore household consent, however elegant on paper, keep failing in practice. The chart below sets out indicative ranges.



It prompts a question that deserves to be asked more often than it is: *at what point does another £1 billion spent on abatement deliver less benefit than £1 billion spent on healthcare, education, flood resilience,* nature recovery, air quality or fuel poverty*?* This is not a rhetorical device, and it is emphatically not an argument against net zero. It is the question every government implicitly answers whenever it chooses what to fund, and the UK government has in fact published its answer: departments appraise policy using a central carbon value of £280 per tonne in 2030 (2020 prices; about £350 in 2026 prices).[34] Measures far to the right of that line — £630-per-tonne forced retrofits, c. £800-per-tonne hydrogen heating (our estimate) — cost more per tonne than the government's own valuation of the benefit they buy. That is an illustrative comparison of a whole-life abatement cost against a single carbon value, not the full appraisal the Green Book prescribes, which would set the rising carbon-value trajectory against every other cost and benefit of each measure; but a full appraisal would have to overturn the ranking, not merely refine it. Money spent there is money not spent on cheaper tonnes elsewhere, or on the adaptation that a warming climate will demand regardless. A country that gold-plates its most expensive abatement ends up with less decarbonisation, not more, and less resilience besides.

It is fair to ask — as thoughtful critics have — whether an analysis anchored to the £280 appraisal value survives a change of political weather. The appraisal value is, after all, a Whitehall instruction rather than a market price: the traded UK ETS price has recently sat far lower, at roughly £35–70 per tonne, and a future government under fiscal pressure — of whatever colour — could revise the official valuation down rather than up. If the £280 figure were doing the load-bearing work, the strategy would inherit its fragility.

It is not — provided the arithmetic is done at the margin, where policy is actually made. The relevant comparison is not between two national pathways averaged across every home, but between the next tonne each pathway buys in the hard-to-treat stock. Table 1 does that for one such home on a common basis: the hybrid's tonnes cost around £340 at the prices households pay, and about £245 on the Green Book's own resource-cost basis — with the policy levies that are transfers rather than costs stripped out of the electricity price — or about £250 with kit at the bottom of today's quoted range, and about £420 and £330 where a new boiler is bought with the heat pump. The government's £280 value is in 2020 prices; in today's money it is roughly £350.[34] Forced full electrification of the same home costs around £490 a tonne without deep fabric work at retail prices and £370 on the resource-cost basis, and around £630 with it (£585 on the resource-cost basis; £490–920 across the £25,000–40,000 capital range at retail prices). At the appraisal value, in other words, the hybrid passes on the paper's own 5% rate — comfortably on the

resource-cost basis, narrowly at retail prices with the boiler retained and not quite when a new boiler is bought with the heat pump — the deep retrofit does not on any basis, and the heat pump without fabric work sits close enough to the line that the discount rate decides, a question taken up below. Work down the curve to the traded price and the conclusion sharpens rather than reverses: at £70 a tonne, let alone £35, nothing in the hard-to-treat stock passes on carbon value alone — which is precisely the case for buying its tonnes in order of cost and deferring the dearest, not for buying the dearest first. A government that adopted the traded price as its true valuation of carbon would not abandon the two-network strategy; it would be driven towards it, because the rational response to a low carbon value is to buy only the cheapest tonnes available: electrify where electrification is cheap per tonne, and retain the gas network for the rest.

Whose discount rate is being used matters as much as whose prices. Table 1 is drawn at 5% real, an investor's rate. The Treasury appraises at the Green Book's 3.5%, and at that rate, on the resource-cost basis, the hybrid's tonnes cost about £235 with the boiler retained and £290 at boiler end-of-life, and the heat pump's without fabric work about £315 — all inside the £350 line — while the deep retrofit's cost about £460 and stay outside it.[34] The government's test, properly applied, does not fail the heat pump in the hard stock; it fails the forced retrofit. The household's test is harsher. A heat pump bought at boiler end-of-life is paid for from savings or on unsecured credit, and the rates households reveal in energy-efficiency decisions run at 8–10% and above: at those rates the heat pump without fabric work costs £600–700 a tonne at the prices households pay, the deep retrofit £900–1,100, and the hybrid £365–385 with the boiler retained or £505–565 at boiler end-of-life. The hybrid moves least because its capital is smallest — a shift of about £65 between 3% and 10% with the boiler retained and £195 at end-of-life, against £285 for the heat pump and £620 for the deep retrofit — which makes it the option whose economics depend least on who is doing the discounting. New build is the exception that explains the rule: there the heat pump's cost sits in the house price and the mortgage, the fabric is built to the standard the pump needs and the alternative is a gas connection that would later be stranded, so the household's rate and the Treasury's coincide — which is why nobody argues about new build, and the whole argument is about retrofit. The gap between the two rates in the existing stock is the adoption failure of Sections 2 and 3 in a single number: the Treasury's arithmetic says the heat pump is worth having, the household's says it is not, and nothing in the current instruments bridges that gap for the hard stock.

The two-network strategy is therefore robust across the whole range of defensible carbon values — which is exactly what one should demand of a strategy that must survive successive governments. At the government's appraisal value and discount rate — £280 in 2020 prices, roughly £350 in today's money, at 3.5% real — the hybrid's tonnes in the hard stock pass on either cost basis with the boiler retained (about £325 at retail prices, £235 on the resource-cost basis) and on the resource-cost basis at boiler end-of-life (about £290), and the forced deep retrofit's do not on any; a national full-electrification pathway only appears to clear the bar because its cheap tonnes, in the homes that suit heat pumps, are averaged with its dear ones — and both strategies buy those cheap tonnes anyway. At traded values of £35–70, no measure in the hard stock passes, and the only rational sequencing is cheapest first, which is the two-network path. It is robust to fuel prices too, as 2026 demonstrated: a doubling of wholesale gas improves the running-cost case for the heat-pump half of every hybrid and raises the value of every unit of gas a hybrid does not burn, while leaving the capital-cost barrier to full electrification of the hard stock exactly where it was. One element of this paper is genuinely policy-contingent, and we flag it where it arises: the green-gas upside of Section 6 leans on carbon being priced meaningfully, in a way the core two-network case does not.

It is robust, finally, to the price ratio itself — which is a policy variable, not a fact of nature, and could move either way. Three futures deserve stating. The first is the rebalancing this paper asks for: moving the policy costs still carried on electricity — Ofgem's price-cap allowance is about £106 a year for a typical dual-fuel household, roughly 2–4p per kWh of electricity — to taxation takes the ratio to about 2.8–3.1:1 and the break-even coefficient of performance to about 2.5–2.8; a deeper rebalancing worth 6p per kWh in all, reaching network and CfD costs as well, would take the ratio to about 2.5:1 and the break-even coefficient of performance to about 2.3; funding that 6p through gas bills instead takes the ratio to about 2.1:1. The second is market reform: as more of the fleet is contracted under CfDs, and if the reform of national pricing goes further towards contracted power, the link between retail electricity and the marginal gas plant loosens, so that a gas shock of the 2026 kind no longer passes straight into the ratio. The third runs the other way: the network programme — an estimated £90 billion by 2031 across gas and electricity networks on Ofgem's RIIO-3 final determinations (Ofgem press release, December 2025) — is recovered through bills, and unless peak demand is contained the electricity share of it pushes the ratio up — which is the 88-gigawatt argument of

Section 4 restated in bill terms. Re-running Table 1 across that range makes the point.[34] At 2.5:1 the hybrid's tonnes cost about £215 and the full heat pump's without fabric work about £340 — both inside the appraisal value — while the deep retrofit's are still about £555; at 4:1 the figures are roughly £450, £615 and £700. A lower ratio does not change the ordering; it enlarges the segment for which the full heat pump is the right answer — the caveat Section 8 already carries — and improves the heat-pump half of every hybrid. At no ratio in the range do forced-retrofit tonnes become the cheap ones.

Two counterweights stop this logic sliding into an excuse for inaction, and both deserve stating. The first is that the expensive tail cannot simply be abandoned: national carbon targets are territorial by legal design, because a world in which every country defers its hardest tonnes to someone else never decarbonises the hard sectors at all. The second is the learning curve: some early deployment of expensive technology is an investment in making it cheap, as offshore wind demonstrated — though, as Section 6 noted, part of that cost fall came from cheaper, de-risked capital as well as hardware,[18] and the learning-curve argument is strongest for manufactured, scalable kit and weakest for labour-intensive activity like retrofitting kitchens, where costs have shown little tendency to fall with volume.

> *"Judged in cumulative carbon per pound — the only measure the atmosphere respects — the sequenced path wins on environmental grounds, not merely fiscal ones."*
>
> — Alistair Ray, Chief Investment Officer, Dalmore Capital

The synthesis is neither 'spend whatever net zero costs' nor 'stop at the easy bits'. It is: buy tonnes in order of cost; use instruments that reveal true costs rather than assert them — auctions and contracts-for-difference, not grant schemes calibrated to consultants' estimates; and hold the expensive tail open rather than forcing it early, letting stock turnover, technology learning and green gas supply deflate its cost before the country is obliged to buy it. That is precisely what the two-network strategy operationalises for heat. A hybrid system buys 60–80% of a hard-to-treat home's tonnes now, at roughly £235–385 each across the price bases and discount rates examined, or £55–180 more where a new boiler is bought with the heat pump — at or around the government's own carbon value, and falling as the kit gets cheaper — and defers the last, dearest tonnes until they are cheaper to buy. The alternative buys those same dear tonnes today, at roughly £460–1,100 where deep fabric work is needed, with money that could have purchased twice the abatement elsewhere or a flood defence besides. Judged in cumulative carbon per pound — the only measure the atmosphere respects — the sequenced path wins on environmental grounds, not merely fiscal ones.

For investors, this discipline is where fiduciary duty and environmental outcome converge rather than conflict. Capital positioned in cheap-tonne assets — biomethane, storage, flexibility, the enabling networks — is on the right side of a public-spending test that can only tighten as the transition's bills arrive. Capital positioned in expensive-tonne strategies carries a risk that is rarely priced: the political system's eventual refusal to keep paying. Several European governments are already rediscovering the limits of consumer tolerance for heat policy costs — Germany's repeal of its 65% renewable-heating rule in July 2026 is the clearest case; strategies that depend on overriding that tolerance are not conservative, whatever their sustainable investment labelling. Britain — and Europe more broadly — will increasingly have to grapple with the £1 billion question, and portfolios built as though it will never be asked are the ones with the most to lose.

12. THE POLICY AGENDA

None of what this paper proposes requires heroic invention. Six measures, all with precedent, would move the system decisively:

1. Plan for two networks, not one. NESO and the CCC should carry a planned two-network pathway as a core case in system planning — generation, networks and storage sized for hybrids in the hard-to-treat stock rather than for their full electrification — using the supply assessment NESO has now published and a cost basis of the kind set out in Table 1.13

2. A green gas contract-for-difference to succeed the GGSS from 2028: auctioned, feedstock-indexed, and funded from gas bills. The extension of the existing scheme's commissioning deadline to 2030, in force from October 2026, buys time; it is not a successor.[17]

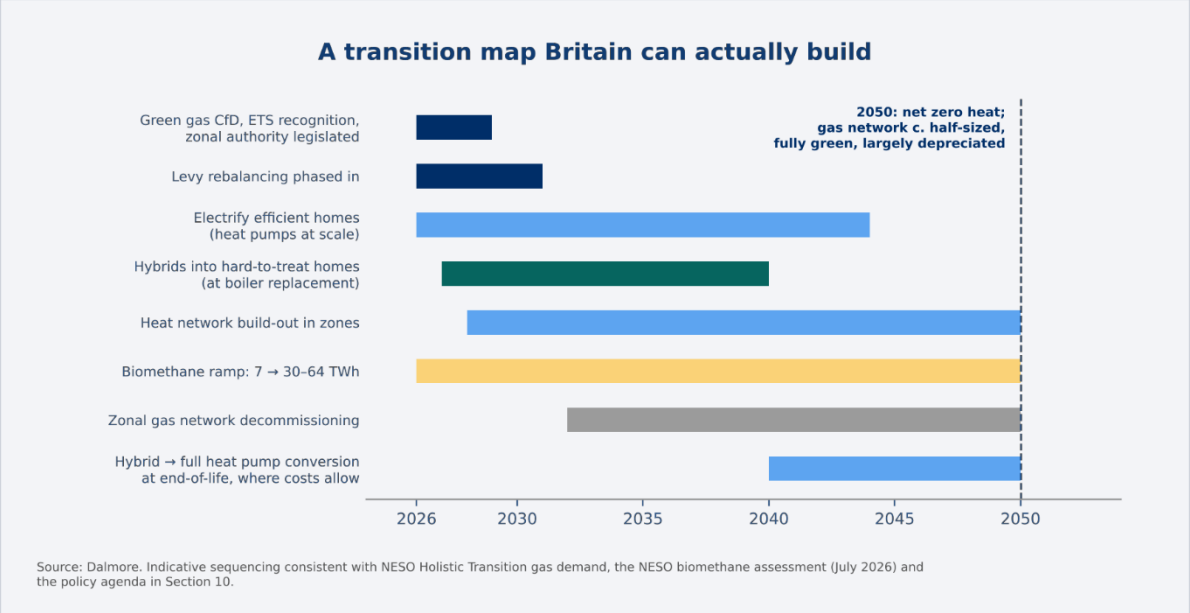
3. Recognition of biomethane in the UK ETS, aligning the UK with the EU ETS and creating the demand-side pull for green gas.[29]

4. Hybrid eligibility for heat policy — reversing the exclusion reaffirmed in April 2026 with a Boiler Upgrade Scheme grant reflecting the hybrid cost delta, and full Clean Heat Market Mechanism credits where paired with a certified green gas tariff.[28]

5. Structural levy rebalancing to correct the electricity-to-gas price ratio — 3.3:1 under the temporary relief of 2026, about 3.5:1 without it (3.6:1 on the previous cap) — that penalises every form of electrified heat. The 2026 measures moved cost to the taxpayer for six months and for three years; the rebalancing needs to be permanent and built into the levies themselves.[7,8]

6. Zonal heat planning authority — extending heat network zoning, and the regulations now in preparation under it, into a general power to plan, street by street, which areas electrify, which connect to heat networks, and which retain gas — with network decommissioning following the map rather than chance.[23]

Sequenced, the programme looks like this — front-loaded policy, two decades of deployment, and a managed landing:



13. IMPLICATIONS FOR INFRASTRUCTURE INVESTORS

We manage capital for investors who take environmental outcomes seriously, and it is precisely on those terms that this thesis should be judged. The relevant test for a pound of infrastructure capital is not whether the asset it buys contains the word 'renewable', but how much carbon it abates, how fast, and at what cost to the households who ultimately pay. On that test, the assets that enable the two-network transition score highly — and several of them sit in markets that generalist energy-transition capital has largely overlooked.

Biomethane production. Scaling from 6–7 TWh towards the c. 30 TWh NESO says can be reached before material trade-offs arise — let alone its 64 TWh pathway — implies a multi-billion-pound buildout of anaerobic digestion capacity over two decades — with revenues that a CfD regime would render quasi-regulated, strong circular-economy characteristics, and rural employment effects.[15] The UK's position well behind France and Denmark is, from an investor's perspective, catch-up growth with a European operating playbook already written.[16] Platform strategies — aggregating sub-scale plants, professionalising operations, securing feedstock — suit mid-market infrastructure capital far better than they suit either utilities or global mega-funds.

Gas and long-duration energy storage. A system designed around rare-event dispatchable capacity assigns explicit value to storage of every duration: batteries for intraday flexibility, long-duration technologies under the cap-and-floor regime whose first sixteen projects Ofgem provisionally selected in June 2026 (final awards due this autumn), and seasonal gas storage whose insurance value becomes legible — and contractable — once the residual gas system is planned rather than residual by accident, as a support framework, if the Government adopts one, would begin to do. These are complementary positions, not competing ones; the optimal-share logic of Section 4 implies the system buys both electrons and molecules of flexibility.

Flexible generation and data centre energy. Gas peaking capacity with a credible green gas transition path captures the convex tail; behind-the-meter generation for data centres — particularly biomethane-backed configurations — monetises the connection-speed arbitrage documented above while remaining compatible with corporate net-zero commitments.[22,28]

Heat networks. Zoning legislation is quietly creating a new regulated-adjacent asset class in urban heat, with mandatory connection powers, long-duration demand and inflation-linked characteristics familiar to any infrastructure allocator — and, since January 2026, a Government goal of 7% of England's heat by 2035, and an expectation of about a fifth of building heat by 2050, behind it.[23]

Gas networks themselves. Accelerated depreciation of new gas distribution investment front-loads capital recovery, supporting cash yields through the transition; the terminal question — the size and funding model of the residual network — is precisely the policy agenda above, and investors are not passive observers of it. Constructive engagement with the zonal planning and CfD agenda is both good policy and good portfolio defence.[24]

A final point on positioning. Nothing here is a bet against electrification — the strategy's largest single component is heat pumps, and its success accelerates rather than retards the electricity buildout by making its peak financeable. It is a bet that the transition will be won by system economics rather than by slogan, and that capital which understands the whole system — electrons and molecules, generation and storage, easy homes and hard ones — will both do more decarbonising and be paid better for it than capital which follows the crowd into the most visible assets.

14. CONCLUSION

Britain is currently attempting the most expensive version of heat decarbonisation — full electrification of one of Europe's oldest housing stocks — and it is visibly falling short: so far short that in 2026 the Government lowered the target rather than lift the delivery. A better-sequenced strategy is available: electrify what suits electrification, network what suits density, and bridge the hard remainder with hybrid systems on progressively greener gas, retiring the gas network zone by zone as genuine alternatives mature. The engineering case is sound; the economics favour it on a common basis across a wide range of assumptions — and across the gas prices of 2026; what is missing is

institutional — a plan that carries two networks rather than one, an authority to draw the map, and a contract to green the molecule. It also needs more green gas than the low-trade-off case alone supplies: within NESO's 30 TWh the residual domestic load would take most or all of it, so the strategy rests on the 64 TWh pathway's land-use choices, on imports of the kind the Dutch green-gas blending obligation, due to take effect in 2027, is designed to permit, or on a smaller residual household share — an allocation NESO says government should settle through a cross-sector assessment of the highest-value end uses, without proposing a hierarchy itself, and one this paper does not pretend to settle. None of that requires heroic invention. Countries a short ferry ride away are already doing much of it, and Germany has just changed course to join them.

For investors, the attraction is that the thesis pays under multiple futures. If the two-network pathway is adopted, the enabling assets — biomethane, storage, flexibility, heat networks — are the direct beneficiaries. If the consensus pathway somehow accelerates instead, most of those same assets are what an all-electric system leans on hardest. The capital at genuine risk is the capital that assumes the current trajectory — high ambition, low delivery — persists indefinitely. That is the one outcome the country cannot afford.

Britain has framed heat as a choice between gas and electricity. It is not.

The real choice is between a transition affordable enough to happen, and one that is theoretically perfect but politically and economically unattainable.

Infrastructure investors should position for the transition Britain can actually build.

15. ABOUT DALMORE CAPITAL AND ROYAL LONDON ASSET MANAGEMENT

Dalmore Capital is part of Royal London Asset Management, the asset management arm of Royal London. Dalmore Capital is a UK infrastructure investment manager overseeing more than £5.7 billion of capital on behalf of institutional investors. The firm currently manages a diversified portfolio of 128 infrastructure assets accumulated since its formation in 2009, across Core, Core+ and PPP social infrastructure assets.

16. NOTES AND REFERENCES

1. Climate Change Committee, The Seventh Carbon Budget (2025). Direct emissions from buildings account for c. 17% of UK territorial emissions, of which c. 70% is from homes (residential buildings were 12% of UK emissions in 2023, with gas about 80% of residential building emissions). Non-residential buildings account for the remainder; the share was c. 18% in 2024 on CCC Progress Report 2025 data.

2. MCS, The 2025 Low Carbon Landscape: just over 60,000 certified heat pump installations in 2025, a record, with the Boiler Upgrade Scheme funding nearly half of them. Figures are MCS-certified installations and therefore understate the total market (which includes some new-build and non-certified installations), but the trend and order of magnitude are unaffected by the choice of dataset. 2026 pace: Boiler Upgrade Scheme applications reached a record 8,150 in July 2026 and c. 7,500 in August, with vouchers paid in August c. 40% above August 2025 (DESNZ scheme statistics); the “a third faster” full-year case is a hypothetical, not a forecast: MCS-certified installations were down 17% and DESNZ retrofit installations down 22% in January–June 2026 against the same period of 2025 (MCS, 2026 Low Carbon Landscape; DESNZ heat pump deployment statistics, 10 September 2026). BUS applications and vouchers lead installations; the July record coincided with the new £9,000 off-gas route (3,037 of 8,150 applications). Heat Pump Association, UK heat pump sales reach record high in 2025 (first reported 12–13 February 2026; HPA web post dated 26 March 2026): 125,037 heat pumps sold in 2025 on factory-gate data (excluding air-to-air), 110,353 of them hydronic (the 27% rise on 2024 is for the 125,037 total); sales count new-build, commercial and non-certified installations and stock, so they are not comparable with MCS-certified installations — the text gives the shortfall ratios on both measures.

3. DESNZ/BEIS, Heat and Buildings Strategy (2021): ambition for a UK market capacity of at least 600,000 hydronic heat pump systems a year by 2028, and an intention to phase out new and replacement gas boiler installations from 2035. Warm Homes Plan (21 January 2026): “more than 450,000 annual heat pump installations in existing and new buildings by 2030” (technical annex), of which the technical annex estimates c. 200,000 in new-build homes — leaving c. 250,000 for existing homes; no date for ending gas boiler sales; Boiler Upgrade Scheme funding of £295m (2025–26), £400m (2026–27), £600m, £683m and £709m (2029–30), £2.7bn in total; £2bn for consumer loans; £1.1bn for heat networks, with 7% of England's heat by 2035 and about a fifth of UK building heat demand by 2050; hydrogen: "As hydrogen is not yet a proven technology for home heating, a role would come later and likely be limited." Future Homes and Buildings Standard (written ministerial statement, 24 March 2026): in force from 24 March 2027 with a 12-month transition period, requiring low-carbon heating such as heat pumps and on-site renewable generation — which effectively rules out gas boilers in new homes.

4. Climate Change Committee, Seventh Carbon Budget balanced pathway: heat pump installations in existing homes rising from 60,000 in 2023 to nearly 450,000 a year by 2030 and around 1.5 million a year by 2035 (Executive Summary).

5. English Housing Survey 2023–24, energy efficiency of the housing stock (England only; A–C 52%, E–G 9%, so D c. 39%; band shares rounded and band D derived). Dwelling age: about a fifth of English homes were built before 1919 (EHS 2023: 20% of owner-occupied, 31% of private rented and 7% of social rented homes; the EHS 2014–15 Housing Stock Report put the figure at 20% of all dwellings), and the older the home the likelier solid walls — in the EHS 2023–24 Climate Resilient Homes fact sheet, 64% of the c. 8.9 million pre-1945 homes had uninsulated solid walls. Timing: UK Green Building Council (2019), “80% of the buildings we will use in 2050 have already been built”.

6. Author estimate, built up from component costs (BEIS, Update of Domestic Cost Assumptions, 2017: solid-wall insulation c. £7,000–20,000 per home) and industry quotations; not a published DESNZ figure. Deep retrofit of solid-wall properties (wall insulation, glazing, ventilation) plus heat pump installation typically totals £25,000–40,000 per dwelling. Annualised at a 5% real discount rate over 30 years, £25,000–40,000 is £1,600–2,600 a year before replacements. Energy Systems Catapult, Electrification of Heat demonstration (installation statistics report): 742 heat pumps installed across the full range of targeted property types and ages, 163 of them in pre-1945 homes, at an average total cost of about £14,800 per property including the heat pump unit, additional measures and installation (Energy Systems Catapult, Electrification of Heat: Home Surveys and Install Report); the proposition that particular archetypes are unsuitable for heat pumps "is not supported by the project data". Hybrid installations — an air-source heat pump added alongside an existing, retained boiler — typically cost £5,000–8,000 per manufacturer and installer guidance (e.g. Worcester Bosch, Hybrid Heat Pump Cost, 2026), the low end of a wide range: 2026 market guides quote retrofit hybrids at c. £7,500–11,000 and factory-matched hybrid units at c. £9,000–14,000. This scoping matters: integrated hybrid systems installed as a single unit, or with major associated works, are quoted materially higher (c. £9,000–14,000 pre-grant in current market guides). A like-for-like boiler replacement costs c. £3,500 on average (Energy Saving Trust, 2026). Figures are manufacturer and installer guidance rather than independent data, and are treated as indicative throughout.

7. Ofgem energy price cap, 1 October – 31 December 2026, direct debit: electricity 26.32p/kWh (with VAT removed from household electricity from 1 October 2026 to 31 March 2027), gas 7.97p/kWh (including 5% VAT) — a ratio of 3.3:1, and a break-even coefficient of performance of approximately 3.0 against a 90%-efficient boiler, before standing charges. The preceding cap (1 July – 30 September 2026) was 26.11p and 7.33p, both including 5% VAT — 3.6:1 and a break-even COP of approximately 3.2 — and the ratio returns to about 3.5:1, with a break-even COP of about 3.1, when the VAT relief lapses; like for like, the underlying electricity rate rose c. 6% between the two caps. Ofgem attributed the October rise in gas to higher wholesale prices "as a result of the ongoing conflict in the Middle East": the Strait of Hormuz closed to shipping at the start of March 2026 and NBP wholesale gas for winter delivery stood at c. 188p/therm (c. £64/MWh; day-ahead c. 177p) on 2 October 2026, and c. 217p by 21 October.

8. The Climate Change Committee (Seventh Carbon Budget, February 2025) has recommended rebalancing policy levies away from electricity bills to improve the relative economics of electrification, and NESO (Future Energy

Scenarios 2025, July 2025) points to “reducing the price of electricity relative to gas” and “addressing high levies”. The Warm Homes Plan (January 2026) did not include rebalancing. Autumn Budget 2025 moved 75% of the domestic cost of the Renewables Obligation to the Exchequer for three years from April 2026 (c. £88 a year per household, on HM Treasury's estimate) and ended the Energy Company Obligation (c. £59); the electricity VAT cut (announced 21 July 2026) runs from 1 October 2026 to 31 March 2027 only, at c. £850m, by the cancellation of the digital ID programme. Both are time-limited and neither restructures the levies.

9. Guidehouse / Green Gas Taskforce, Bio-Hybrids: A Clean Heat Solution (February 2026). Published by the Green Gas Taskforce (the report does not state who funded the modelling), whose members include gas network operators; we cite its stock modelling as the most granular available while noting the interest of its sponsors.

10. Cadent, written evidence to a UK parliamentary inquiry (PMP0019, November 2020), Figure 4: 2050 GB system peak electricity demand of c. 204 GW in a fully electrified scenario versus c. 116 GW in a “balanced” scenario in which hybrids (heat pumps with hydrogen boilers) are the dominant solution, from c. 59 GW in 2020; the modeller is not named. Stonehaven, The Heat Decarbonisation Two-Step (March 2026, supported by Cadent): hybrid deployment avoids c. £21.5bn of distribution network capex to 2050 and c. £830m/yr of levelised reinforcement cost compared with standalone high-temperature heat pumps in the c. 18% of English homes needing major internal works (secondary reinforcement only). Both are gas-industry publications; treated as indicative.

11. L. Hirth, 'The market value of variable renewables', Energy Economics 38 (2013): the marginal value of wind and solar declines with penetration as output becomes correlated with low prices. On the cost of the last increments: N. A. Sepulveda, J. D. Jenkins, F. J. de Sisternes and R. K. Lester, 'The role of firm low-carbon electricity resources in deep decarbonization of power generation', Joule 2(11), 2018, pp. 2403–2420 — across nearly 1,000 cases, firm low-carbon resources reduce the cost of fully decarbonised systems by 10–62%; and the Royal Society, Large-scale electricity storage (September 2023), which estimates a 2050 need in Great Britain for 60–100 TWh of hydrogen storage, mainly in salt caverns, to manage periods of low renewable generation.

12. NESO, Future Energy Scenarios. In FES 2025 (Table 2) the Holistic Transition pathway has 168 TWh of natural gas demand (including biomethane, c. 64 TWh) and 120 TWh of hydrogen demand in 2050, c. 39% in total of the 743 TWh of natural gas demand (including exports) in 2024; residential gas demand in that pathway is c. 3 TWh.

13. NESO, Exploring the Role of Biomethane in the Energy System to 2050 (July 2026; published 30 July; version 2 of 15 September 2026, which updates footnotes and references): c. 6 TWh injected in 2025 (less than 1% of gas demand); c. 30 TWh a year deliverable by 2050 without major trade-offs; up to 64 TWh (FES 2025 pathways) feasible but within a range where NESO believes a cross-sector assessment of ambition is needed; NESO does not say how much of the 64 TWh depends on grassland, but notes that some feedstock potential depends on the 38% reduction in livestock numbers in the CCC's balanced pathway; feedstock potentials in NESO's figure 6 (external analysis by Alder BioInsights, up to 108 TWh for Great Britain by 2050, medium scenario; values as reported by Bioenergy Insight): grassland 29 TWh, rotational crops 27 TWh, sequential crops 17 TWh, agricultural residues 15 TWh, livestock waste 11 TWh (the components listed sum to 99 TWh); current levelised production costs of £73–135/MWh against natural gas, including carbon, at £26–70/MWh by 2050; c. 4 MtCO2/yr of biogenic removals available at 30 TWh if all plants captured CO2. Green Gas Taskforce, A Green Gas Future: Outlining the Feedstock Potential for Biomethane Generation (published 1 October 2025): sufficient sustainable UK feedstock for c. 50 TWh/yr by 2030 and c. 120 TWh/yr by 2050 (prepared by Alder BioInsights), which argues that cropping for AD should not be seen as competing with food production — industry-supported analysis. The residual domestic load estimate in Section 6 is author arithmetic: c. 22 million homes and businesses connected to the gas distribution networks (Ofgem, RIIO-3 Final Determinations overview, December 2025; DESNZ counts 24.9m gas meters across all sectors in 2024) and c. 280 TWh of domestic gas demand today (DESNZ 2024: domestic gas was 64% of the 438 TWh weather-corrected GB total; up to c. 300 TWh in a colder year, an author sensitivity); 30–40% of homes retaining a connection, mostly as hybrids using 20–40% of former consumption, implies c. 25–35 TWh on central assumptions; the full span of those inputs is c. 17–48 TWh, and the comparison with NESO's 30 TWh sets national supply against domestic demand alone, before industry, power and transport. Illustrative.

14. Baringa / Green Gas Taskforce, Green Gas Britain: Reducing the Cost of Net Zero with Biomethane (October 2025): scaling sustainable biomethane could reduce the energy-system cost of reaching net zero by c. £150–220bn (ESME modelling; central case c. £174bn); production costs for a typical project could fall c. 25% if key barriers are removed. Commissioned research; the headline range assumes biomethane output above 100 TWh in all scenarios, i.e. the feedstock case above.

15. Baringa / Green Gas Taskforce, Biomethane: Building Sustainable UK Value (2026): c. 57,000 jobs by 2050 (of which c. 15,000 in rural communities, with a c. 20% wage premium to regional average wages) and c. £70bn of cumulative GVA to 2050, on a central-growth case of c. 111 TWh of production by 2050. The jobs estimate is for the c. 111 TWh case; at 30 TWh it would be proportionately smaller.

16. Cadent, Accelerating Biomethane in the UK (November 2025); GRDF et al., Panorama des gaz renouvelables 2025 (April 2026). France's regulator-supervised 'right to inject' framework shares connection and reinforcement costs between producers and consumers; 803 anaerobic digestion plants injected into French networks at end-2025 (13.6 TWh, 3.9% of French gas consumption), c. 700 of them on distribution networks. Cadent's Ofgem-supported 'bid window' clustering model for sharing reinforcement costs moves away from first-connector-pays; Cadent's web pages (January–March 2026) report 47 biomethane plants connected with c. 4 TWh of installed capacity — more than half of UK production on Cadent's c. 7 TWh figure — and 38 applications in its first Entry Reinforcement Assessment Window (closed 6 March 2026), with a second window expected to open in early 2027. Denmark: biogas supplied more than 40% of Danish gas consumption in 2025 (Biogas Danmark, as reported 8 January 2026).

17. The Green Gas Support Scheme closes to new Stage 1 applications on 31 March 2028. DESNZ announced on 10 December 2025 an intention to extend the commissioning deadline to 31 March 2030; the Green Gas Support Scheme (Amendment) Regulations 2026 were laid before Parliament in September 2026 and came into force on 16 October 2026 (made on 23 September 2026; Ofgem published draft guidance v3.0 on 24 September 2026 and final guidance in October 2026). The Government said it expected to consult on a long-term biomethane framework by the end of the 2025/26 financial year (Secretary of State's reply to ADBA, September 2025; written answer UIN 90871, 21 November 2025); no consultation had been published by 5 October 2026. ADBA's open letter to the Prime Minister and Chancellor, delivered on 7 September 2026 with more than 170 signatories, asks the Government to fix the GGSS, which the letter says has run out of money, and to recognise biomethane in the UK ETS; the Budget of 28 October 2026 is the next decision point. See Greening the Molecule, Section 6.

18. Contracts for Difference Allocation Round 5 (2023) received no offshore wind bids; AR6 (2024) cleared fixed-bottom offshore wind at £58.87/MWh for new projects and £54.23/MWh for re-bids from AR4 (2012 prices; ORE Catapult and Westwood Energy analyses of the AR6 results) — well above the 2019 lows of c. £40 but roughly half the real cost of a decade earlier. Cheaper, de-risked finance was a key driver of the fall in offshore wind strike prices (ORE Catapult, Offshore Wind Cost Reduction: Recent and future trends in the UK and Europe, 2017); Aldersey-Williams, Broadbent and Strachan (Energy Policy 128, 2019), working from audited project accounts, found no clear cost trend among early-round projects but estimated that lower-risk finance could cut offshore wind LCOE by 20–30% against the 8.9% discount rate they used (as clarified by the authors in 2021). We are not aware of a published split of the fall between finance and hardware; the Crown Estate's 2012 cost-reduction pathways projected finance at c. 6% of the fall to 2020 against c. 39% for technology and supply chain (a forecast).

19. HyDeploy trials (led by Cadent) at Keele and Winlaton produced the safety evidence for blending up to 20% hydrogen by volume in the distribution network; the HSE's assessment of that evidence and a Government decision to enable blending were still outstanding at the time of writing. Because hydrogen carries roughly one-third of methane's energy per unit volume, a 20% volumetric blend delivers only c. 7% of energy — and therefore at most c. 7% of point-of-use emissions abatement, and only if the hydrogen is itself low-carbon.

20. DESNZ strategic policy decision (December 2023) seeing potential strategic and economic value in supporting blending of up to 20% hydrogen by volume in gas distribution networks in certain circumstances, subject to the outcome of the HSE safety assessment and further economic analysis, primarily as an offtaker of last resort for hydrogen producers.

21. The proposed hydrogen-for-heating village trials at Whitby and Redcar were cancelled in 2023 and work on a hydrogen town pilot was deferred in 2024 until after the Government's decision on whether hydrogen has any role in home heating; the Climate Change Committee's Seventh Carbon Budget sees “no role for hydrogen in buildings heating”. DESNZ, Hydrogen heating: overview (updated 24 March 2026): hydrogen is "not yet a proven technology for home heating", any future role would come later and would "likely be limited", and Government "will consult in due course" on whether it should have any role; HSE's own assessment (March 2026) found conversion “potentially feasible”, with no fundamental safety barriers identified but a full evidence demonstration “not made at this time”. SGN's H100 Fife trial (c. 300 opted-in homes) is the only hydrogen-for-heating trial the DESNZ page describes.

22. Applicants for the Government's AI Growth Zones must demonstrate access to at least 500 MW of power capacity by 2030 (DSIT, AI Growth Zones: open for applications, April 2025); electricity connection timelines in constrained areas can exceed a decade, against 12–18 months for gas connections. The five GB gas distribution networks together received c. 86 data centre connection enquiries between August 2024 and July 2025 (Stonehaven).

23. Energy Act 2023, Part 8: heat network zoning in England, empowering designated zones within which certain buildings can be required to connect to heat networks. Government response to the zoning consultation (21 January 2026): a national Heat Network Zoning Authority (initially within DESNZ, later the Warm Homes Agency), local zone coordination bodies, connection notices (where the zone developer requests them) for new buildings, existing communally heated buildings and existing non-domestic buildings with a wet system above 100 MWh a year, implementing regulations anticipated for spring 2026 (not yet laid at the time of writing) and carbon-intensity limits from 2030; the Act does not yet allow a connection charge on mandated connections, which the Government intends to address through primary legislation. Warm Homes Plan (January 2026): £1.1bn for heat networks; 7% of England's heat by 2035 and about a fifth of UK building heat demand by 2050.

24. Ofgem, RIIO-3 sector methodology and RIIO-GD3 Final Determination (December 2025): acceleration of depreciation for new gas distribution assets added to the regulatory asset value in RIIO-GD3 (from April 2026), to be paid back by 2050; no acceleration for existing distribution assets, gas transmission or electricity networks, front-loading capital recovery while the customer base remains broad.

25. Netherlands: April 2021 plan led by Netbeheer Nederland (with Techniek Nederland and Natuur & Milieu) for up to 2 million hybrid heat pumps before 2030; hybrid heat pumps are eligible for ISDE subsidy; on 7 October 2026 the cabinet announced (letter to the Tweede Kamer from the housing minister on behalf of the climate minister; a coalition-agreement commitment) that, from 2029, a smart hybrid heat pump becomes “the new standard” at boiler replacement for homes not on a heat network, framed around lower gas use and grid congestion. The Government's own wording is “standard”; press reports describe it as mandatory, while exemptions and the legal mechanism are still being worked out (Dutch Government news release, 7 October 2026). Germany: the Building Modernisation Act (Gebäudemodernisierungsgesetz), passed by the Bundestag on 10 July 2026 and in force from 29 July, replaces the 2023 Building Energy Act's requirement that new heating systems draw 65% of their energy from renewables with technology-neutral rules on the fuel burned (alongside carbon pricing under the separate national and EU schemes), permitting heat pumps, district heat, hybrids, biomass or conventional boilers, and introducing minimum shares of biogenic or other climate-neutral fuel for anyone installing a new gas, oil or LPG heating system from 2029 (10% in 2029, 15% in 2030, 30% in 2035, 60% in 2040), with a separate supplier quota on green gas and green heating oil planned and due to be legislated by 1 December 2026; evaluation due 2030.

26. Author analysis for this paper. Starting point: Ofgem's published gas network charges for a typical dual-fuel household are c. £165 a year for distribution and c. £13 for transmission at 2025/26 prices, c. £178 in total (Ofgem, RIIO-3 Final Determinations impact assessment, December 2025, Table 2; £209 and £16 by 2030/31 under the final determinations). Scaling that charge by the share of today's cost retained divided by the share of customers retained: halving the customer base with planned, zonal decommissioning (costs falling to c. 70–80% of today's) implies c. £250–285/yr (c. £265 at 75%); halving it with costs falling only to c. 90–95% of today's under unplanned attrition implies c. £320–340/yr (c. £355 if no cost falls away). With 30–40% of customers retained, as assumed in Section 6, and costs at 70–80% of today's, the same method gives c. £310–475/yr. Illustrative.

27. A condensing boiler converts c. 90% of gas energy to heat at the point of use. The alternative chain at system peak — CCGT at c. 55% efficiency, c. 7–8% transmission and distribution losses, then a heat pump at a cold-weather COP of c. 2 — delivers c. 1.0 units of heat per unit of gas (1.1 before network losses; lower still if the marginal plant is older or open-cycle): a marginal thermodynamic gain purchased at the cost of the entire peak generation and network capacity chain. Inputs: c. 55% is a good existing CCGT — DESNZ's assumption for a new-build H-class CCGT is c. 60% (net, LHV), which would give c. 1.1 after losses, and for open-cycle plant c. 40%, which would give c. 0.7 (DESNZ, Unabated gas electricity generation costs, 2025); network losses are c. 6% in distribution (National Grid) and c. 7–8% across transmission and distribution (UK Power Networks; Utility Week).

28. Stonehaven, Solving the AI Energy Dilemma (April 2026), sponsored by Cadent. Modelled large data centre: grid electricity at 22.15p/kWh (c. £155m/yr) versus on-site gas generation fuelled at 4.53p per kWh of gas (c. £104m/yr including engine capex, for a modelled 100 MW facility), a c. 33% total-cost reduction; a biomethane-backed configuration at 7.01p/kWh is below grid cost only if biomethane injections are recognised in the UK ETS (the paper's proposed reform); on current treatment (9.01p/kWh, c. £173m/yr) it is c. 12% above grid. Commissioned research; conclusions on connection timelines are consistent with independent reporting on grid queues. Note also: fossil-fuel hybrids have never qualified for the Boiler Upgrade Scheme, and the Boiler Upgrade Scheme (England and Wales) (Amendment) Regulations 2026 (SI 2026/390, in force 28 April 2026) reaffirm the exclusion — the heat pump must meet the property's full space-heating demand alone, and any supplementary appliance must not be fossil-fuelled — while adding a £2,500 tier for air-to-air systems; the standard grant is £7,500, with £9,000 for off-gas-grid homes replacing oil or LPG heating from 21 July 2026 to 31 March 2027 (Ofgem guidance v5.1). The Clean Heat Market Mechanism government response for scheme year 2 (31 October 2025) set the 2026–27 target at 8% and deferred any change to hybrid credits to Year 3 and beyond; hybrids remain at half a certificate under the Clean Heat Market Mechanism Regulations 2025 (SI 2025/81, reg. 13(2)). Guidehouse (note 9) recommends a £2,500 hybrid grant (with a consultation on the full £7,500 for bio-hybrids installed with evidence of a green gas tariff) and full CHMM credits for bio-hybrids with a green gas tariff.

29. The UK Emissions Trading Scheme does not currently credit emissions reductions from biomethane injected into the grid, unlike the EU ETS, whose Monitoring and Reporting Regulation (Article 39) allows grid-injected biomethane to be zero-rated where sustainability and double-counting conditions are met.

30. Typical gas boiler service life is 10–15 years (Which?), so boilers installed in the mid-2030s will in many cases still be operating in 2050. Replacements are frequently distress purchases made in days — about 30% of heating-system replacements follow a breakdown (Ipsos MORI/Energy Saving Trust, cited by Nesta), and in a Which? survey 39% of homeowners who had not planned faced an emergency replacement, with 63% of emergency cases waiting more than a day for heating — which structurally favours like-for-like replacement.

31. Great Britain's gas networks deliver roughly four times the energy of the electricity network on a peak winter day (NESO, FES 2025, Table 2: 1-in-20 gas peak demand of c. 5,200 GWh/day against a 58 GW electricity peak, i.e. under c. 1,400 GWh/day). Storage that discharges only in rare system events must recover its full capital cost from those events, which is why NESO's scenarios retain dispatchable gas-CCS and hydrogen-fired capacity to 2050. FES 2025 capacity in 2050 (REA analysis of FES 2025): gas with carbon capture c. 50 GW in each net-zero pathway; unabated gas 0 GW in Holistic Transition, 6 GW in Electric Engagement and 11 GW in Hydrogen Evolution. Centrica, Chris O'Shea (The Times, 2 September 2026; centrica.com, 4 September): Rough — the UK's largest store, which Centrica says now provides about half of UK storage capacity — is "practically empty, as markets currently do not make it financially viable", and will "close by the spring" unless included in the existing regulatory support model; c. £2bn of investment offered. DESNZ, Gas System in Transition: Security of Supply, interim response (18 August 2026): most respondents doubt the market alone will maintain storage; cap-and-floor the operators' preferred mechanism, with RAB and CfD models also raised and a strategic reserve under consideration; "minded-to" positions to follow.

32. See also Utility Week, 'UK could generate 120 TWh of biomethane annually by 2050', and REA coverage of the Green Gas Taskforce reports, for wider reporting of the feedstock and value studies cited above.

33. UK territorial emissions have roughly halved since 1990 while the economy has grown by almost 90% (ONS real GDP), driven principally by the exit from coal power, renewable generation and industrial change (DESNZ, UK

greenhouse gas emissions statistics, including the provisional 2025 figures of 367 MtCO2e, 54% below 1990; CCC progress reports).

34. DESNZ, Valuation of Greenhouse Gas Emissions for Policy Appraisal: central carbon value of £280/tCO2e in 2030 (2020 prices — roughly £350 in 2026 prices once uprated with the GDP deflator, which is the basis on which the chart's appraisal line is drawn), used across government cost-benefit analysis; the traded UK ETS price has been far lower, c. £35–70/t (c. £60/t on DESNZ's September 2026 average and c. £63/t on 19 October 2026; the appraisal guidance was unchanged as at 5 October 2026). The marginal abatement cost chart shows indicative, author-estimate ranges for illustration rather than project-level appraisal, on the whole-life basis of Table 1 (Section 3): a hybrid at c. £340/t at today's retail prices and equipment costs (c. £245/t on a resource-cost basis, with policy levies stripped from the electricity price; c. £250/t with kit at £5,000 — a grant, being a transfer, does not change the national cost); a heat pump without deep retrofit at c. £490/t (c. £370/t resource basis); a heat pump with deep retrofit at c. £630/t (c. £585/t resource basis), c. £490–920/t at retail prices and c. £440–870/t on the resource basis across the £25,000–40,000 range; hydrogen heating c. £800/t. The chart shows each hard-to-treat row as a range from the Treasury's basis (3.5% real, resource cost) to a household's (10% real, retail prices), per the discount-rate sensitivity below; the hybrid is shown twice, with the boiler retained and at boiler end-of-life. Table 1's model — 12,500 kWh of useful heat (c. 2.5 tCO2/yr on gas), 30 years at 5% real, replacements and standing charges included, grants excluded — is author arithmetic and should be read as illustrative. Price-ratio sensitivity (retail basis, gas held at 7.97p/kWh, everything else as Table 1): at ratios of 2.0 / 2.5 / 3.3 / 3.6 / 4.0 the cost per tonne is c. £135 / £215 / £340 / £385 / £450 for the hybrid, c. £245 / £340 / £490 / £540 / £615 for the heat pump without deep retrofit, and c. £505 / £555 / £630 / £660 / £700 for the heat pump with deep retrofit; the break-even coefficient of performance against a 90%-efficient boiler is 0.9 times the ratio. The 2.5:1 case corresponds to removing c. 6p/kWh from the electricity unit rate (author assumption: more than the policy levies now itemised in the cap, so a deeper reform); c. 2.1:1 to recovering the same amount through gas bills (taking gas to c. 9.5p/kWh). Policy-cost allowance: Ofgem, Summary of changes to the energy price cap (April–June 2026), c. £106 a year for a typical dual-fuel customer, down from £236. Illustrative. Discount-rate sensitivity (everything else as Table 1): at 3.0 / 3.5 / 5 / 8 / 10% real the cost per tonne is c. £325 / £325 / £340 / £365 / £385 for the hybrid at retail prices (c. £230 / £235 / £245 / £275 / £295 on the resource basis); c. £410 / £430 / £490 / £610 / £695 for the heat pump without deep retrofit (c. £295 / £315 / £370 / £495 / £580); and c. £470 / £510 / £630 / £900 / £1,095 for the heat pump with deep retrofit (c. £425 / £460 / £585 / £850 / £1,045) — or c. £345–700 across the £25,000–40,000 capital range at 3.5% on the resource basis and c. £860–1,560 at 10% at retail prices. HM Treasury, The Green Book: social time preference rate of 3.5% real for years 0–30 (3.0% for years 31–75). Household rates: mortgage finance at c. 2–3% real, unsecured credit in high single digits, and the implicit discount rates of 10% and often well above, up to 20% or more, that the energy-efficiency literature has found since Hausman (1979, c. 20% for room air-conditioner buyers) and Train (1985), reviewed in Gillingham and Palmer (2014): J. A. Hausman, 'Individual discount rates and the purchase and utilization of energy-using durables', Bell Journal of Economics 10(1), 1979, pp. 33–54; K. Train, 'Discount rates in consumers' energy-related decisions: a review of the literature', Energy 10(12), 1985, pp. 1243–1253; K. Gillingham and K. Palmer, 'Bridging the energy efficiency gap: policy insights from economic theory and empirical evidence', Review of Environmental Economics and Policy 8(1), 2014, pp. 18–38. Illustrative. Boiler timing: Table 1's hybrid adds a heat pump to a serviceable boiler with ten years of life left (boiler replacements in years 10 and 25), whereas the like-for-like comparator buys a new boiler now; at boiler end-of-life the hybrid is a new boiler bought with the heat pump — £10,000 now and in year 15 — which adds c. £130 a year to the annual equivalent at 5% and c. £80 a tonne: c. £370 / £385 / £420 / £505 / £565 at retail prices and c. £275 / £290 / £330 / £410 / £470 on the resource basis at 3.0 / 3.5 / 5 / 8 / 10%. An integrated hybrid unit at c. £12,000 (note 6) would cost c. £540/t at 5% at retail prices (c. £450/t on the resource basis) — above the heat pump without deep retrofit — which is why the case rests on the add-on route. Illustrative.

35. UK gas boiler sales ran at c. 1.45–1.5 million units a year in 2024–25 (industry estimates, e.g. EHI). Heat pump cost trend (chart): author-compiled indicative nominal averages for air-source installations from MCS cost data, c. £10,900 in 2021 rising to c. £13,300 in 2025 — consistent with MCS's reported average of c. £12,950 in January 2025 and with DESNZ Boiler Upgrade Scheme statistics (published 29 January 2026; later releases exist), which put the mean cost of BUS-funded air-source installations at £13,431 (8.4 kW average) in October–December

2025. In real terms the median BUS installation cost has fallen by c. 11% since the scheme opened in 2022, part of it through a shift to smaller systems, and was flat in the latest year (DESNZ BUS summary business case, 2026; Nesta, 30 April 2026). The Boiler Upgrade Scheme grant was £5,000 for air-source heat pumps from the scheme's launch in April 2022 (£6,000 for ground-source) and was raised to £7,500 in October 2023.

36. Cumulative emissions chart: author analysis for this paper, illustrative scenarios only. Both pathways are constructed to reach a near-zero endpoint by 2050; the two-network path abates earlier through hybrid adoption at the natural boiler-replacement cycle from the late 2020s. Both trajectories are logistic curves from 65 MtCO2e in 2025 to 5 MtCO2e in 2050 (midpoints 2040.5 and 2036.8, steepness 2.3 and 3.0 years, each pinned to its end-points by a small linear correction); the c. 200 MtCO2e figure is the integral of the difference between them, is sensitive to the adoption, timing and grid-decarbonisation assumptions those parameters stand for, and is presented to make the cumulative-emissions point, not as a forecast.

37. Basis: 12,500 kWh of useful heat a year; price cap for October–December 2026 (electricity 26.32p, gas 7.97p per kWh; gas standing charge £108 a year); boiler at 90%; hybrid heat pump carrying 75% of heat at a seasonal COP of 3.0 with the boiler covering the rest; C at a COP of 2.6 in an uninsulated home; D's fabric work cutting heat demand by 30% and lifting the COP to 3.2; 0.183 kg CO2 per kWh of gas and 0.10 kg per kWh of electricity averaged over thirty years; grants excluded — a grant moves cost from the household to the taxpayer without reducing it: with the £7,500 Boiler Upgrade Scheme grant, C costs the household c. £2,170 a year but the country still £2,650. The resource-cost basis strips the policy levies (transfers, in Green Book terms) from the electricity price, taking it to c. 20p/kWh (an illustrative deeper-reform assumption, see note 34), and VAT from gas (7.5p). With VAT restored on electricity (c. 3.5:1), B costs £40 and C £62 a year more; at 2026's crisis gas prices (10p/kWh), A costs £280 a year more and B £70. None of this counts the system cost of Section 4 — the peak capacity a cold-snap heat pump in an uninsulated home demands — which falls on every bill payer rather than this household. Author arithmetic; indicative. At boiler end-of-life — a new boiler bought with the heat pump, £10,000 now and again in year 15 — B's annual equivalent is c. £2,320 and its tonnes cost c. £420 at retail prices and c. £330 on the resource-cost basis: dearer than with the boiler retained, still the cheapest of the three on every basis (note 34).



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